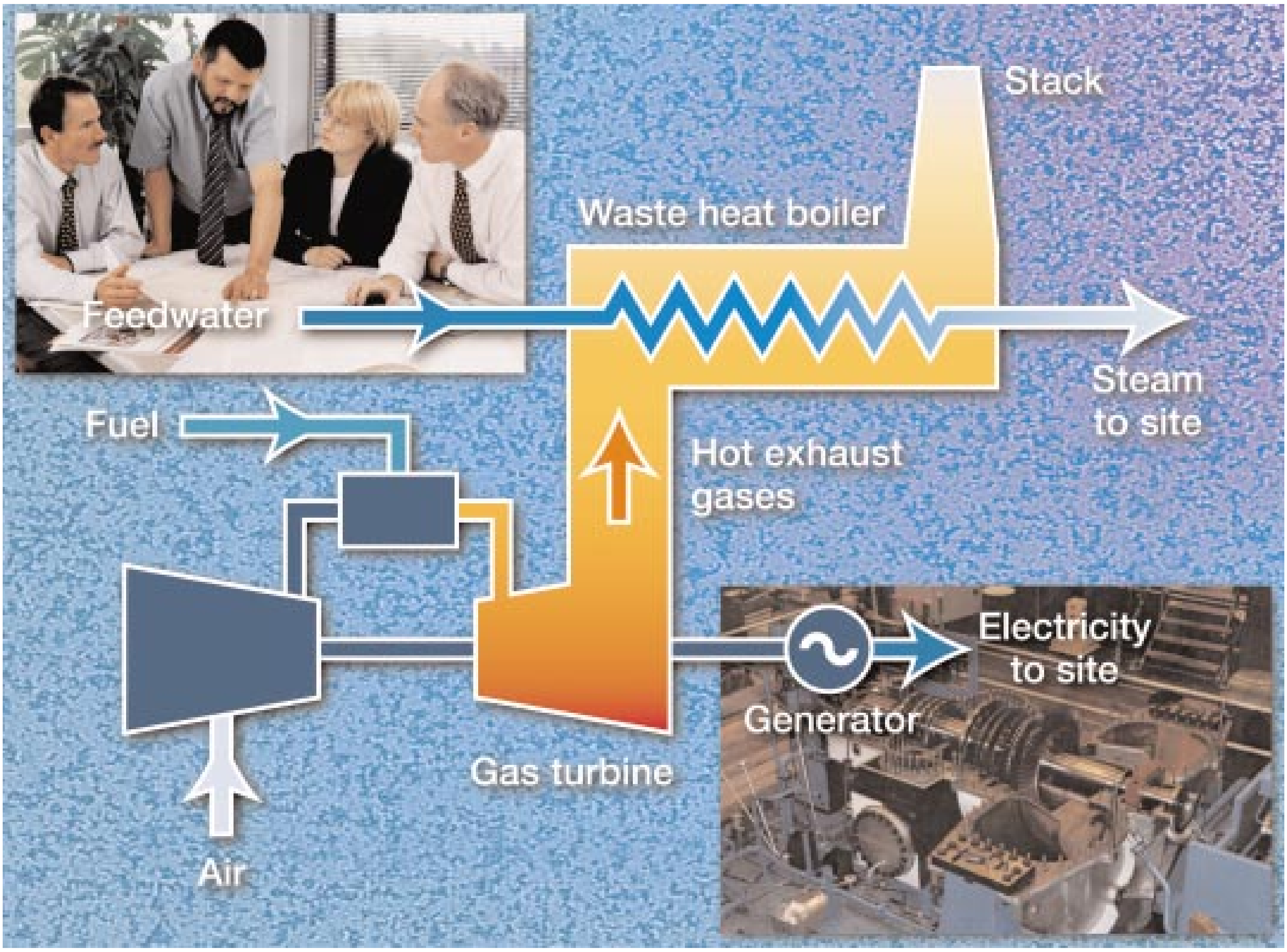
GOOD PRACTICE GUIDE 43

Introduction to large-scale combined heat and power



GOOD PRACTICE GUIDE 43

BEST PRACTICE PROGRAMME

ENERGY EFFICIENCY

BEST PRACTICE PROGRAMME

INTRODUCTION TO LARGE-SCALE COMBINED HEAT AND POWER

This Guide is No 43 in the Good Practice Guide series and is designed to give managers an overview of the fundamental technical and financial aspects involved when considering large-scale Combined Heat and Power (CHP). It covers CHP plant which is applicable to large industrial, commercial and public sector sites, in the range 500 kW to more than 20 MW of electrical output. Plant below this range is classed as small-scale CHP and is covered by Guides 1 and 3.

Prepared for the Department of the Environment, Transport and the Regions by:

ETSU
Harwell
Didcot
Oxfordshire
OX11 0RA

Cover photograph showing a steam turbine under construction, courtesy of Peter Brotherhood Ltd.

First published 1992 Revised and reprinted March 1999

LIST OF RELEVANT GOOD PRACTICE GUIDES

1. GUIDANCE NOTES FOR THE IMPLEMENTATION OF SMALL-SCALE PACKAGED COMBINED HEAT AND POWER
3. INTRODUCTION TO SMALL-SCALE COMBINED HEAT AND POWER
30. ENERGY EFFICIENT OPERATION OF INDUSTRIAL BOILER PLANT
60. THE APPLICATION OF COMBINED HEAT AND POWER IN THE UK HEALTH SERVICE
69. INVESTMENT APPRAISAL FOR INDUSTRIAL ENERGY EFFICIENCY
115. AN ENVIRONMENTAL GUIDE TO SMALL-SCALE COMBINED HEAT AND POWER
116. ENVIRONMENTAL ASPECTS OF LARGE-SCALE COMBINED HEAT AND POWER
197. ENERGY EFFICIENT HEAT DISTRIBUTION
220. FINANCING LARGE-SCALE CHP FOR INDUSTRY AND COMMERCE
221. IMPROVING BOILER ENERGY EFFICIENCY THROUGH WATER TREATMENT
226. THE OPERATION AND MAINTENANCE OF SMALL-SCALE COMBINED HEAT AND POWER
227. HOW TO APPRAISE CHP – A SIMPLE INVESTMENT APPRAISAL METHODOLGY

Copies of these Guides may be obtained from:

Energy Efficiency Enquiries Bureau
ETSU
Harwell
Didcot
Oxfordshire
OX11 0RA
Tel No: 01235 436747. Fax No: 01235 433066. E-mail: etsuenq@aeat.co.uk

Overseas customers please remit £3 per copy (minimum of £6) with order to cover cost of packaging and posting. Please make cheques, drafts or money orders payable to ETSU.

FOREWORD

This Guide is part of a series produced by the Government under the Energy Efficiency Best Practice Programme. The aim of the programme is to advance and spread good practice in energy efficiency by providing independent, authoritative advice and information on good energy efficiency practices. Best Practice is a collaborative programme targeted towards energy users and decision makers in industry, the commercial and public sectors, and building sectors including housing. It comprises four inter-related elements identified by colour-coded strips for easy reference:

— *Energy Consumption Guides:* (blue) energy consumption data to enable users to establish their relative energy efficiency performance;

— *Good Practice Guides:* (red) and *Case Studies:* (mustard) independent information on proven energy-saving measures and techniques and what they are achieving;

— *New Practice projects:* (light green) independent monitoring of new energy efficiency measures which do not yet enjoy a wide market;

— *Future Practice R&D support:* (purple) help to develop tomorrow's energy efficiency good practice measures.

If you would like any further information on this document, or on the Energy Efficiency Best Practice Programme, please contact the Environment and Energy Helpline on 0800 585794. Alternatively, you may contact your local service deliverer – see contact details below.

ENGLAND

London
Govt Office for London
6th Floor
Riverwalk House
157-161 Millbank
London
SW1P 4RR
Tel 020 7217 3435

East Midlands
The Sustainable Development Team
Govt Office for the East Midlands
The Belgrave Centre
Stanley Place
Talbot Street
Nottingham
NG1 5GG
Tel 0115 971 2476

North East
Sustainability and Environment Team
Govt Office for the North East
Wellbar House
Gallowgate
Newcastle-upon-Tyne
NE1 4TD
Tel 0191 202 3614

North West
Environment Team
Govt Office for the North West
Cunard Building
Pier Head
Water Street
Liverpool
L3 1QB
Tel 0151 224 6401

South East
Sustainable Development Team
Govt Office for the South East
Bridge House
1 Walnut Tree Close
Guildford
Surrey
GU1 4GA
Tel 01483 882532

East
Sustainable Development Awareness Team
Govt Office for the East of England
Heron House
49-53 Goldington Road
Bedford
MK40 3LL
Tel 01234 796194

South West
Environment and Energy Management Team
Govt Office for the South West
The Pithay
Bristol
Avon
BS1 2PB
Tel 0117 900 1700

West Midlands
Regional Sustainability Team
77 Paradise Circus
Queensway
Birmingham
B1 2DT
Tel 0121 212 5300

Yorkshire and the Humber
Sustainable Development Unit
Govt Office for Yorks and the Humber
PO Box 213
City House
New Station Street
Leeds
LS1 4US
Tel 0113 283 6376

NORTHERN IRELAND
IRTU Scientific Services
17 Antrim Road
Lisburn
Co Antrim
BT28 3AL
Tel 028 9262 3000

SCOTLAND
Energy Efficiency Office
Enterprise and Lifelong Learning Dept
2nd Floor
Meridian Court
5 Cadogan Street
Glasgow
G2 6AT
Tel 0141 242 5835

WALES
Business and Environment Branch
National Assembly for Wales
Cathays Park
Cardiff
CF10 3NQ
Tel 029 2082 5172

CONTENTS

1. INTRODUCTION

Combined heat and power (CHP) is the on-site generation and use of electricity and heat in a cost-effective and environmentally responsible way. CHP uses either a gas turbine, a steam turbine or a gas-fired or oil-fired engine to drive an electricity generator, and makes practical use of the heat which is an inevitable by-product. This heat can be used for making process steam, space heating, domestic hot water and now, increasingly, for cooling using absorption chillers.

The overall efficiency of such systems can be in excess of 80%, which is far better than conventional power stations. This leads to considerable reductions in emissions of carbon dioxide, nitrogen oxides and sulphur dioxide. CHP is a proven technology, with high reliability. The UK total installed electrical capacity has grown from 2,000 MW_e in 1990 to 3,730 MW_e in 1997, from over 1,360 units. Of these, around 330 are industrial sites, and these account for over 90% of the total installed electrical capacity. Buildings related installations are far more numerous but tend to be of much smaller capacity.

Choosing CHP could boost your profits, increase your security of supply and at the same time, improve your environmental performance. If your site requires heat for at least 4,500 hours a year, then it is likely that CHP would be a worthwhile investment. Under certain circumstances, it may be cost-effective with lower running hours.

This Guide provides an introduction to this complex but potentially cost-cutting technology - a technology which industry can no longer afford to ignore, for economic as well as environmental reasons.

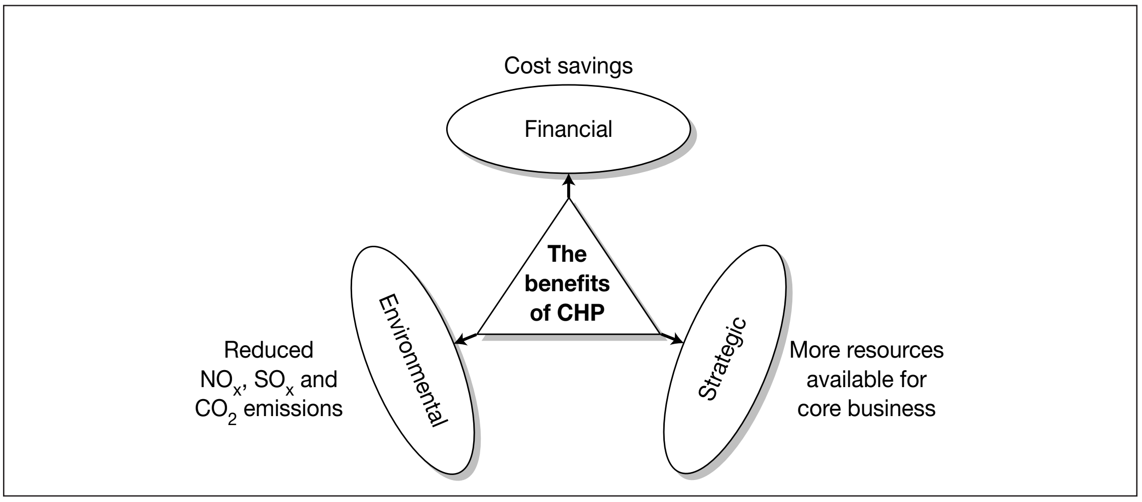


Fig 1 Summary of the benefits of CHP

2. THE CHP EVALUATION AND IMPLEMENTATION PROCESS

2.1 CHP as a Strategic Move

CHP represents a major decision taken at board level. It will involve a major investment or a long-term, legally binding financial agreement and should be considered as an integral part of the overall company strategy. It is essential that your company is in a position to take on the long-term commitment associated with a CHP plant, and is also prepared to accept such a commitment.

The first step must be to answer two key questions:

- ***Have other cost-effective energy efficiency measures been considered?***

  If energy demand can be reduced through other energy efficiency measures, then a smaller CHP plant may be appropriate. This will reduce the cost and may help the proposal to succeed. Conversely, economies of scale may be lost with a smaller plant.

- ***What is your company's long-term strategy?***

  CHP plant has a lifetime of up to 25 years and its economics are typically evaluated over a ten-year period. The full financial benefit of the plant will only be realised when it is operated at close to optimum conditions over the whole of its life. Because the viability of the scheme may be adversely affected by major reductions to the heat or power loads, it is important to determine future demands and load profiles. The historical pattern of heat and power loads may be a useful guide in this process, however, consideration must be given to any new products or processes which are planned and which could influence demand.

2.2 Overview of the Process

This Section gives a summary of how a typical project proceeds from conception to implementation and is summarised in Fig 2. The process may be much more, or slightly less complex, depending on the project value. The relative costs and duration of each stage will depend on the particular project size and experience of participants.

1. Raise awareness of the possibility of CHP with company management and technical staff. Then hold an in-house discussion of strategic implication as raised in Section 2.1, and carry out a general energy savings analysis.

2. Carry out a preliminary assessment based upon Good Practice Guide (GPG) 227 *How to appraise CHP – A simple investment appraisal methodology*. This may take a day or two of your engineers' time gathering relevant data and carrying out the fairly straight forward calculations shown in the Guide. The study examines uses for heat, profiles of heat and power demand, and provides preliminary indication of prime mover options. Initial contact with gas and electricity suppliers may be advisable. The end result might be two or three options for the type and size of plant.

3. Next is a management board meeting to decide whether or not to go for a full feasibility study. This is a significant decision, as such a study could cost over £20,000 for a major scheme, perhaps £10,000 to £20,000 for smaller schemes, and require tens of staff man-days. The board meeting would be based upon the results of the initial design/feasibility study. It takes careful strategic thinking to prepare for this meeting; you should allow between two and five staff days, plus the board time. Financial data will have to be presented with simple payback, costs, reliability forecasts and some different scenarios. It is essential to investigate the likely board preferences and react accordingly.

4. If given the go-ahead for a full feasibility study, the next step is to draw up a project specification and tender documents. These are required to appoint a contractor to carry out the full feasibility study. They define the heat and power demand profiles, including steam

pressures, requirements with regards to contracts/arrangements with electricity and gas suppliers, and will be largely based upon the preliminary assessment above. Options for prime movers would be left open at this stage. In this process, some analysis of funding options should also be requested.

5. Issue the tender documents for appointment of a contractor to carry out the full feasibility study. Fig 3 shows an outline specification for a full feasibility study and will assist when drawing up the specification for the tender. Discussions would inevitably follow to resolve any queries.

   Note: the full feasibility study could of course be done in-house, if appropriate skills are available, but this is becoming less common.

6. Review the tenders and select a contractor. Commission the full feasibility study, which is likely to take around two to three months to complete.

7. Review the full feasibility study. Technical and commercial appraisal is required, and detailed discussions will inevitably follow, with a high probability of revisions being made.

8. The study can then be presented to the board for approval. A decision on the preferred funding route should be made at this stage - i.e. on or off balance sheet, energy services contract etc. This opens up (at least) two possible routes for completion of the project:

   A Energy services contract, or third party financing, where the user delegates responsibility to a contractor after negotiation of detailed terms of supply.

   B Own-finance, where the project is financed and more closely managed by the user-company, and largely managed in-house.

9. Develop the full project specification, compiling data from all work to date and reflecting the board's decisions on financing etc. The specification must define the scope of supply, equipment specifications, site working regulations, timescales etc.

A. Third party route

A10. Compile a short-list of energy services and/or CHP supplier companies and issue requests for tenders to meet the full project specification.

A11. Review the tenders. Discussions will follow and possibly the submission of revised tenders. Submit the preferred final package to the board for sanction.

A12. The next step is often to sign a Memorandum of Understanding, giving a degree of commitment to place a contract. This will help to ensure full co-operation of the supplier, prior to placing a full contract.

A13. Negotiate and let the contract for supply, leading to detail design, procurement, manufacture, site preparation, installation, commissioning, acceptance testing and handover. By this route, user involvement can be relatively minimal.

B. Alternative in-house route

There are two approaches to an in-house contract. Either, placing an order for a turn-key (ready to use) system to a detailed specification drawn-up in-house. Or, to procure components to be assembled and commissioned in-house. There are, of course, options between these extremes.

B10. Appoint a project team and develop a project plan and design.

B11. Place enquiries for the main plant and short-list suppliers. Issue a request for tenders with the full project specification.

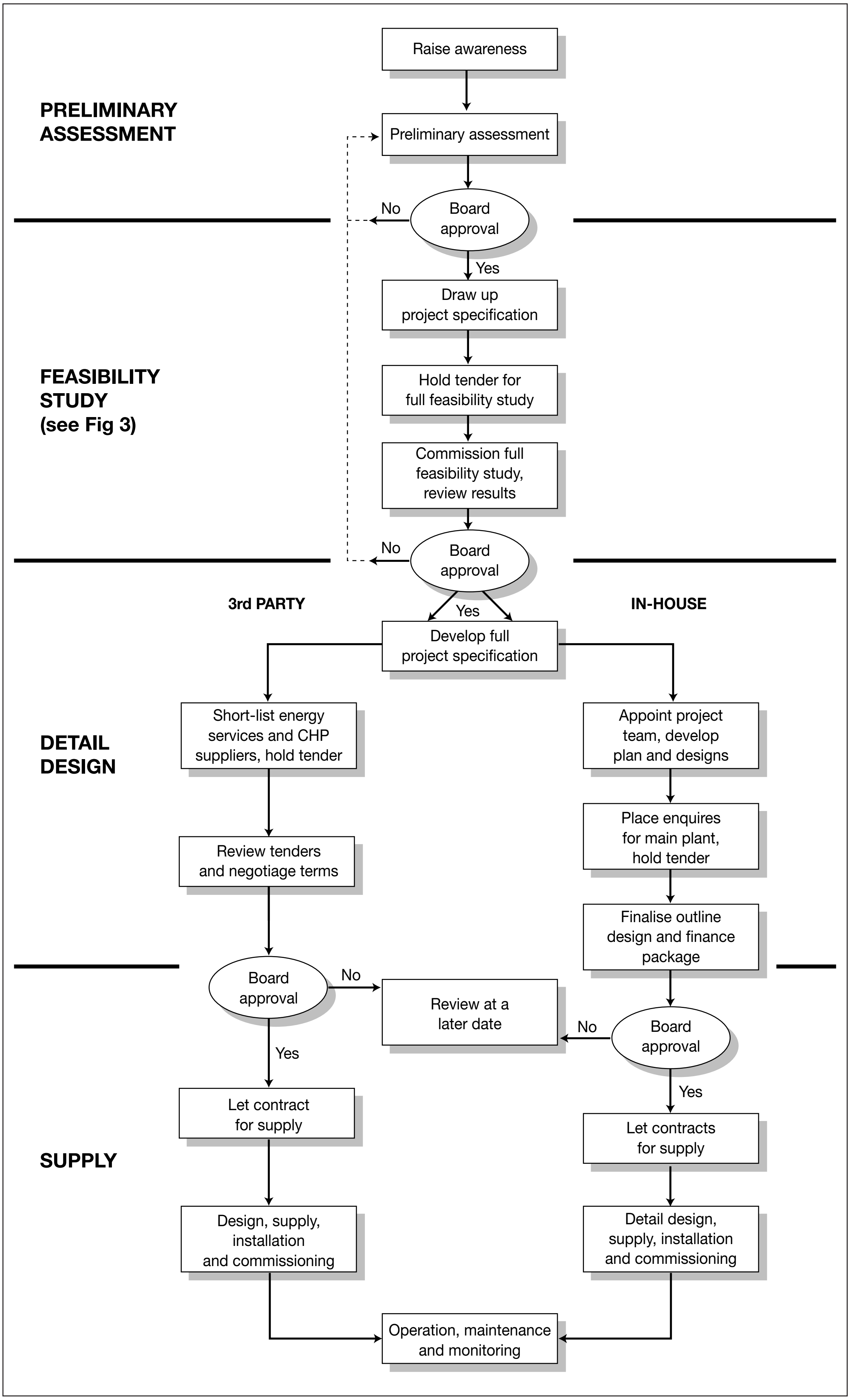


Fig 2 Flowchart showing key steps in a typical CHP project process

General Statement	A detailed feasibility study is required to enable decisions to be made regarding the technical, financial, operational, and environmental implications of installing CHP on the site(s).
Organisation and Geographical Background	Details must be provided to consultants on the nature and development of the site, main contacts for the relevant technical, managerial and financial departments of the company, electricity and gas suppliers, and the original utilities services consultants.
Existing Infrastructure	The feasibility study should investigate the suitability of the existing infrastructure, both electrical and mechanical, to accommodate CHP installation(s), either as a single unit or as a multiple number of smaller units.
Available Data	The tenderer must make provision for generation of data necessary to make competent judgements on the CHP scheme. Current and future energy demands of the site, including annual and daily load profiles, should be verified or established and the CHP unit sized accordingly.
Allocation of Effort	The tenderer should propose a study methodology indicating the level of investigation to be carried out together with detailed information on teams including CVs.
Timescale	The tenderer should provide timescales and milestones.
Financial Considerations	The widest range of financial options using both internal and external funding should be investigated including: • Energy Service Companies (ESCOs). • Contract Energy Management (CEM). • Equipment Supplier Finance. • Outright Capital Purchase.
Economic and Risk Assessments	Long-term running and operational costs should be considered in option appraisals. The economics of CHP are sensitive to variations in the prices of both electricity and fuel - detailed sensitivity analysis should be carried out.
Technology Options	All technical option for the prime mover(s), and all supply infrastructure should be investigated.
Export Electricity Sales	An assessment of the potential for electricity sales to other organisations, taking into account the continuing liberalisation of the UK electricity supply industry, should be carried out.
Connection Agreements	The feasibility study should include financial and technical considerations for the interface with the local gas and electricity distribution networks.
Evaluation of Regulatory Regime	The feasibility study should incorporate an evaluation of regulatory requirements in view of existing legislation and the continuing liberalisation of the gas and electricity industries, highlighting any specific regulatory changes which it is felt might affect the viability of the scheme.
Security of Supply	The study should review the security of energy supply to the site and/or the need for back-up systems.
Space Availability	The space requirements for new equipment and systems must be taken into account for all options reviewed.
Environmental Impact	The feasibility study should incorporate an assessment of environmental impact in terms of emissions of gases and particulates, and noise.
Safety	All implications of existing Health and Safety legislation applicable to the existing and any modified or new plant should be taken into account.
Reporting	The final feasibility report should be completed within Z months from contract placement. In addition to the final report, an interim report could be requested mid-way through the feasibility study.

Fig 3 Outline specification for a full feasibility study

B12. Review the tenders. Discussions will follow and possibly the submission of revised tenders. Submit the preferred final package to the board for sanction.

B13. Place the orders for the components and begin site preparation etc. Installation, commissioning, and acceptance testing will follow.

Finally, begin operation and assessment, dealing with operational problems, testing and performance monitoring. A report back to the board will almost certainly be required after commissioning.

Fig 3 shows a minimum scope of work which should be included in a full feasibility study. Specific site details and other issues to be investigated will have to be added.

2.3 Initial Assessment of Feasibility

Fig 4 gives an introductory flowchart to help evaluate the initial suitability of CHP for your company.

GPG 227 *How to appraise CHP – A simple investment appraisal methodology* and GPG 220 *Financing large-scale CHP for industry and commerce* should be consulted for further guidance.

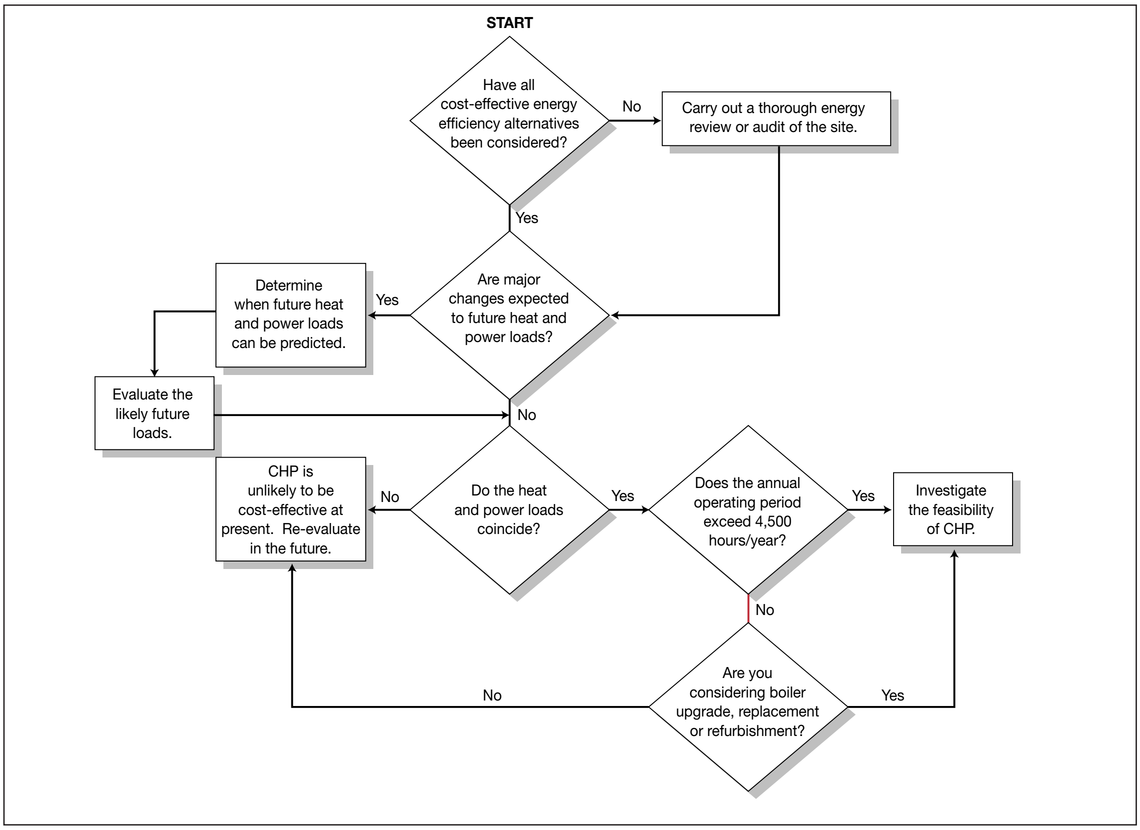


Fig 4 Is CHP an option for your company?

2.4 Energy Profiles

Energy demand profiles (see Fig 5) show the patterns of energy usage over specified time periods. The success of the whole project depends on these profiles and it is essential that appropriate resources are allocated to producing these. The profiles are used during both initial and full feasibility studies as a guide to building an accurate prediction of future load patterns. If data taken over a period of years is not available, short-term monitoring will be required. Monitoring should also be considered in order to verify the existing data. Equipment for this can be bought or hired. See GPG 227 for further details on energy profile analysis.

Heat usage must be split into grades, i.e. according to temperature of use, and separate profiles constructed for each grade, e.g. water at 80°C for space heating, steam at 7 to 20 bar (170°C to 215°C), hot air for drying/curing at 300°C. Air conditioning and refrigeration loads down to ‘intermediate’ temperature (say 5°C) may also be added as equivalent heat loads. A site energy optimisation study should be carried out before investigating CHP and this will review the heat grades in use to ensure that they are as low as is practicable, which will maximise the benefits of any subsequent CHP. The profiles must then be adjusted to allow for the effects of any significant energy conservation measures in progress and planned, and any prospective changes in production plant, operational methods, site occupation hours, other heat loads on site etc.

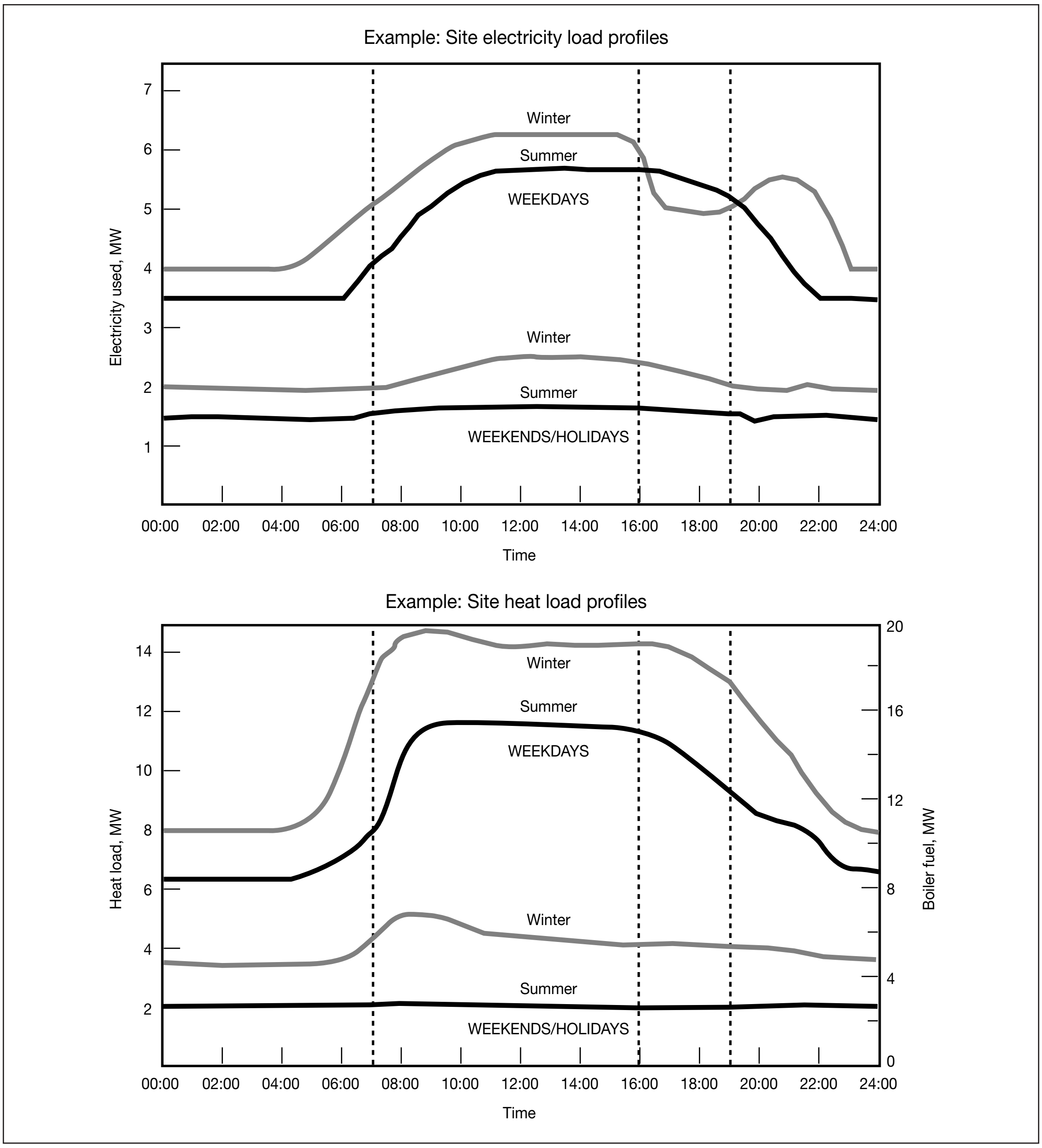


Fig 5 Example electricity and heat load profiles

3. TECHNOLOGY

3.1 Reliability and Availability

These factors are extremely important. CHP must operate over extended periods and in many cases continuously, in order to be economic. In practice, however, a prime mover requires maintenance which necessitates a scheduled shutdown at least once a year, and there may well be additional unscheduled stoppages.

The reliability of a prime mover is thus a measure of its susceptibility to unscheduled shutdown. Its availability takes into account all outages. The distinction between availability and reliability is often blurred and manufacturers' specifications and guarantees should be carefully scrutinised to ensure a true understanding. The time period used is typically a year of 8,760 hours. The formulae below illustrate one method of making the calculations:

$$\% \text{ Reliability} = \frac{T - (S+U)}{T-S} \times 100$$

$$\% \text{ Availability} = \frac{T - (S+U)}{T} \times 100$$

Where S = scheduled maintenance shutdown, U = unscheduled shutdown and T = time period when plant is required to be in service or available for service, all in hours per year.

For example, typical manufacturers' guaranteed figures for a compression-ignition engine burning heavy fuel oil are 876 hours maximum scheduled outage (S) and 438 hours maximum unscheduled outage (U), for a year of 8,760 hours. Using the formulae quoted, this would give:

$$\text{Guaranteed reliability} = \frac{8{,}760 - (876 + 438)}{8{,}760 - 876} \times 100 = 94.4\%$$

$$\text{Guaranteed availability} = \frac{8{,}760 - (876 + 438)}{8{,}760} \times 100 = 85.0\%$$

For gas turbine CHP schemes in fully beneficial continuous operation, long-term availability's in the range 94 - 98% have been achieved.[1] Steam turbines can be confidently expected to have availability's of up to 99%. For reciprocating engines, it is realistic to expect availability's in the range 85 - 92%, depending to some degree on the operation of the site and how hard the engine is worked, i.e. an engine pushed close to its limit is likely to need more maintenance.

3.2 Fuels

Heat from fuel is the primary source of energy for large-scale CHP. This energy is released by burning the fuel with air, so producing large amounts of combustion gases at high temperature. Some of the heat energy is used to pressurise the gases thus providing the force to drive an engine or gas turbine and generate electricity; the de-pressurised and reduced-temperature gases at the exhaust then become the main source of heat for site use. The combustion of some fuels produces contaminants which would damage the prime mover, and the heat energy is first converted to steam which then provides the pressure energy to drive a turbine. This also illustrates a key factor in choice of fuel - its premium value or quality. Non-premium fuels are cheap but incur significant on-costs for handling, burning and meeting environmental regulations; premium fuels are more expensive but have few or no on-costs.

---

[1] References: Good Practice Case Study (GPCS) 208 *The long-term performance of a combined-cycle CHP installation*, GPCS 209 *The long-term performance of an installation using an aero-derived gas turbine* and GPCS 220 *The long-term performance of a gas turbine combined heat and power installation*.

Fuels may be solid, liquid or gaseous, and either ‘commercial’ or ‘waste’. Commercial fuels are fossil fuels which are extracted, treated/refined to varying degrees and sold nation-wide by the producers and distribution companies. Waste fuels are by-products or adjuncts of processing or domestic activities, and are only economic if available locally.

Installations may be designed to accept a choice of more than one fuel. The most widespread example is dual-fuel gas/fuel oil burning, where gas is bought under the advantageous interruptable tariff and is replaced with distillate fuel oil when the gas supply is interrupted during periods of peak demand. When burning a waste product, a back-up fuel may be needed to bridge shortfalls in the supply of waste. Fuels such as hospital waste require gas or oil burners to initiate combustion. True multi-fuel firing, where more than one fuel is used simultaneously, is feasible but rarely necessary and hence seldom encountered.

3.2.1 *Commercial Fuels*

Coal and fuel oils are supplied in bulk and have simple tariff structures. Natural gas is normally drawn from a continuous supply and so the tariff will take account of diurnal and seasonal variations in site demand. In all cases, actual prices are by individual negotiation. UK coal is mostly deep-mined and therefore expensive in world terms but prices are relatively stable. Fuel oil is geared to the world market and prices are liable to fluctuate. Gas prices are relatively more stable. The following are in ascending order of premium.

Coal

Coal is the cheapest fuel in the UK and is non-premium because of its ash and sulphur contents and the relative difficulty of burning it. It is marketed in various grades of size and quality to suit the application. On-costs include site storage and handling, ash disposal, meeting environmental controls, and the capital and running costs of a steam boiler. Much R&D work has gone into applying combustion systems, such as the pressurised fluidised bed, to enable direct application to a gas turbine, but the technology has so far only been used in a few demonstration installations in the 200 to 300 MW_e range.

Fuel oils

Heavy and extra heavy fuel oils are mixtures of residuals from petroleum refining. Properties and composition are more consistent than those of coal. They are Class G and Class H respectively in BS 2869, which defines the main properties of commercial fuel oils and sets maximum limits for contaminants. They contain sulphur and small amounts of water, sediment and ash. Environmental legislation (see Section 4) is expected to enforce a reduction in sulphur content. They are very viscous and require heating to make it easier to pump etc. and further heating before burning. On-costs include storage, handling and heating. Heavy fuel oils are suitable for use in fired boilers, reciprocating diesel engines and some very large gas turbines.

Gas oil

Gas oil is a distillate product of petroleum refining. Its properties and composition are more consistent than Heavy Fuel Oil (HFO), and it is Class A1 and A2 in BS 2869. Apart from sulphur, there are effectively no contaminants. On-costs include storage and handling. Gas oil is a suitable fuel for boilers, engines and gas turbines but, because of its relatively high cost, its use will not normally be economical for CHP, except as a secondary or standby fuel or as pilot fuel for gas-fuelled compression-ignition engines.

Natural gas

Natural gas’ principal constituent is methane and there are no contaminants and no on-costs. Natural gas is suitable for all equipment, though for gas turbines and for many gas engines over $1MW_e$, the gas supplied will normally require further compression.

3.2.2 *Waste as Fuel*

The outstanding advantages of waste fuels are their low or zero initial cost and the potential reduction or elimination of the cost of disposal. Potential disadvantages, however, are the added on-costs of storage and handling, treatment, specialised combustion equipment, flue gas clean-up, etc. as appropriate. Some common waste fuels are described overleaf.

Solid waste fuel
This includes, for example, wood off-cuts from furniture manufacturers, biomass from forestry and farming, waste tyres, domestic refuse, etc. The successful burning of solid waste usually requires specialised technology and consists essentially of incineration to produce steam for CHP. Municipal collection and centralised systems have realised the full benefit of CHP by exporting surplus energy to, for example, communal heating schemes.

Liquid waste fuel
This includes black liquor from wood pulp manufacture. Its treatment and firing as the basis for steam turbine CHP have long been established in the paper industry.

Gaseous waste fuel
This includes off-gas in petroleum refineries and other chemical processing plants, coke oven, blast furnace and Basic Oxygen Steel-making (BOS) gas in steel works. Biogas is impure methane produced during the decay of organic matter, e.g. sludge digester gas in sewage treatment works, landfill gas from municipal refuse tips. Methane may be freely present in coal seams and has to be removed by intensive ventilation to avoid hazard. Biogas and mines gas, and some off-gases, do not need a steam conversion stage and may be fired direct into a prime mover.

3.2.3 *Calorific Values of Fuels*
Calorific Value (CV) is the heat available from a fuel when it is completely burnt, expressed as heat units per unit of weight or volume of the fuel.

The gross, or higher CV, is that determined in the laboratory using a calorimeter. It is the total heat liberated in the complete combustion of the fuel and is determined by measuring the heat removed in cooling the products of combustion to a standard reference temperature, including the latent heat recovered from condensation of water vapour in the combustion products. This water vapour is formed from the combustion of hydrogen and the vaporisation of any moisture present in the fuel.

The net, or lower CV, is determined by calculation and equals the gross CV minus the latent heat of the water vapour from the combustion of hydrogen and any moisture in the fuel. The net CV is more representative of the heat available in practice from the combustion of fuels in equipment such as furnaces and boilers, where the latent heat in the water vapour formed is not normally recoverable (exceptions are condensing economisers and spray recuperators which recover the latent heat).

Different industries may favour either gross or net CV, for example, engine and gas turbine manufacturers use net CV, whereas the boiler manufacturers in the UK use gross CV. Fuel is purchased on the basis of its gross CV.

The use of one or other of these CV's affects the derived energy balance and results in different thermal efficiency figures for combustion plant and equipment, so great care must be exercised. For the most common CHP fuels, the following relationships may help in the interpretation of performance data.

IN THIS DOCUMENT GROSS CALORIFIC VALUE IS USED THROUGHOUT

Table 1 Comparing commercial fuels in terms of gross and net CV

Fuel	**Ratio of gross / net CV**
Natural gas	1.109
Gas oil	1.067
Heavy fuel oil	1.060
Bituminous coal	1.040*

* Depends on moisture content as fired

Table 2 Typical properties of selected fuels

Fuel	CV as normally expressed		Contaminants %		
	Gross	Net	Sulphur	Water	Ash
Steam coal	30.6 MJ/kg	29.7 MJ/kg	1.0	10.0	8.0
Wood waste	15.8 MJ/kg	14.4 MJ/kg	0.4	15	Trace
Heavy fuel oil	41.2 MJ/l	38.9 MJ/l	2.5	0.3	0.04
Gas oil	38.3 MJ/l	36.0 MJ/l	0.2	0.05	0.01
Natural gas	38.0 MJ/m^3	34.2 MJ/m^3	–	Trace	–
Landfill gas	20.0 MJ/m^3	18.0 MJ/m^3	Trace	Trace	–
Mines gas	21.0 MJ/m^3	18.9 MJ/m^3	Trace	5.0	–

3.3 Prime Movers

The prime mover is the mechanical machine which drives the electricity generator. It is the heart of the CHP system and its correct selection is vital for a successful installation. The three main factors governing choice are the fuel(s) available, the grade of heat required on site and the heat:power ratio. Prime movers comprise gas turbines, reciprocating engines and steam turbines, and these are each described below together with the combination of gas turbine and steam turbine called the Combined Cycle.

3.3.1 *Gas Turbines*

The gas turbine (Fig 6) has been the most widely used prime mover for large-scale CHP in recent years. It utilises pressurised combustion gases from fuel burnt in one or more combustion chambers to turn a series of bladed fan wheels and rotate the shaft on which they are mounted, which then drives the generator. This power turbine also drives another turbine which acts as an air compressor, delivering air at high pressure to the combustion chamber(s) to burn the fuel.

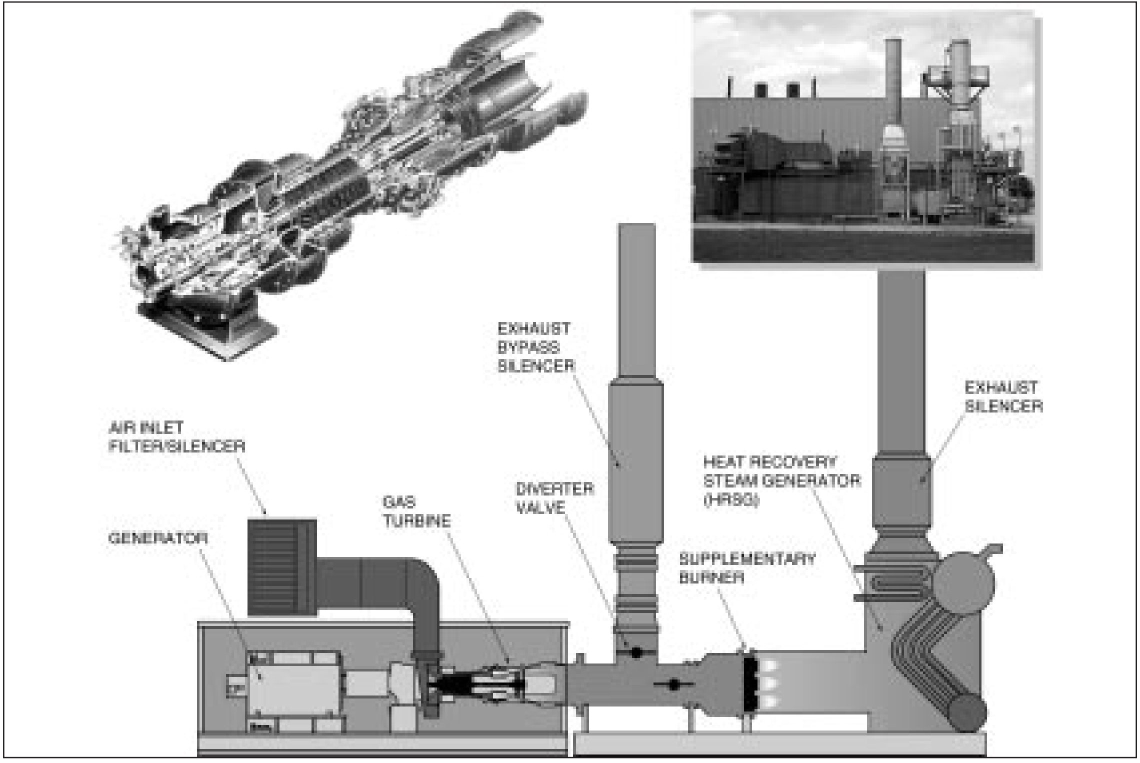


Fig 6 Gas turbine CHP unit diagram (courtesy of Solar Turbines Inc)

Combustion gases are delivered to the power turbine at a temperature in the range of 900 to 1,200°C and exhausted from it at 450 to 550°C. This exhaust is the source of heat energy for the site and makes the gas turbine particularly suited for high-grade heat supply. The usable heat:power ratio ranges from 1.5:1 to 3:1 depending on the characteristics of the particular gas turbine. In order not to exceed metallurgical temperature limits, the gas turbine has to take in much more air than is required for the combustion of its fuel (excess air). Therefore, the exhaust gases contain large amounts of residual oxygen which can burn extra fuel. Such supplementary firing can raise the overall heat:power ratio to as high as 10:1 (although up to 5:1 is more typical) and offers valuable flexibility to serve variable heat loads and also enables the flue gas temperature to be raised to suit higher temperature applications. Since no additional combustion air is required, the use of supplementary fuel has a very high thermal efficiency - up to 88% (gross) of the energy injected with the supplementary fuel can be recovered.

A gas turbine operates under exacting conditions of high speed and high temperature and the hot gases supplied to it must therefore be clean, i.e. free of particulates which would erode the blades, and contain not more than minimal amounts of contaminants which would cause corrosion under operating conditions. High-premium fuels are therefore most often used, natural gas being the most popular and a high standard of air filtration is essential. Distillate oils such as gas oil are suitable, and gas turbine sets capable of using both are often installed to take advantage of interruptable gas tariffs. In principle, residual fuels may be used if sufficiently free of deleterious contaminants, although in practice, this is rare in industrial CHP applications. Waste fuels such as biogas, landfill gas and mine gas are applicable providing their CV's and composition are consistent enough to enable the hot gas temperature leaving the combustion chamber to be controlled at the requisite level. Combustion techniques for producing clean hot gases from solid and other 'difficult' fuels have been developed but are not yet ready for general application in the size range of gas turbine CHP plant considered here.

Gas turbine development has traditionally served two distinct applications; aero and industrial. Aero engines demand maximum power to weight ratio, rapid speed variation, rapid on/off to suit intermittent use and fast servicing and repair. These demands are met by using special and costly materials to operate at temperatures of the order of 1,200°C, plus enhanced technical sophistication generally and modular construction to simplify servicing/repair. Industrial turbines are heavier and more robust, operate at lower inlet temperatures (about 900°C) and, therefore, use conventional and cheaper materials, operate at constant speed and run continuously for long periods between maintenance shutdowns. The need for increased efficiency has prompted the increasing adoption of aero derivative machines and technology for industrial gas turbine applications, and the difference between the two types of machine is diminishing.

There are several other ways of increasing the power output and efficiency of gas turbines. The most significant are the addition of inter-coolers, reheaters and regenerators. The first two improve the efficiency of the compressor and power turbines respectively, but require them to be split into two stages. The third reduces the primary fuel consumption, but also the amount of heat available for site use. Steam or water injection can also be used for power enhancement, and this has the added benefit of reducing NO_x emissions. For steam injection, high-pressure, high-quality steam is required and consequently, the practice is more commonly encountered on the larger machines. Water injection is normally used primarily for NO_x suppression and requires de-mineralised water of very heavy purity. The use of machines having any or all of these arrangements depends on the trade-off between increased complexity and capital cost and the benefit realised.

The generation efficiency (the proportion of heat in the gas turbine fuel converted to electrical output at generator terminals) can range from 20 to 35% (gross CV basis) depending on the inlet temperature and pressure and other power-enhancing facilities employed. About 30% (gross CV) is typical in practice, and 41.8% is the stated target of current R&D work. Gas turbines should, however, be operated at good load factors; the efficiency of the single-shaft smaller machines falls off markedly when operated below about 70% of rated output, although the larger twin-shaft units have much better part-load performance.

Gas turbines are available in a wide power output range from less than 1 MW_e to over 200 MW_e. A turbine is typically mounted on the same sub-base as the generator, with a step-down gearbox between the two to reduce the high shaft speed of the turbine to that of the generator. A suitable foundation is required for the sub-base. Gas turbines are extremely noisy and are generally housed in an acoustic enclosure which, for industrial applications, is usually located in a factory-type building to provide weatherproofing and further noise attenuation. Enclosures are fitted with fire and gas detection systems, and have a CO_2 system for fire suppression. The air is taken from outside the enclosure and the intake ducting is fitted with filters to remove dust and a silencer to minimise noise. The selection of the method of containment should also aim to minimise operator exposure to the hazards that can result from a major mechanical failure.

Gas turbines have inherent high reliability and a minimal running maintenance requirement. Shutdown maintenance is required at extended intervals and is usually carried out by the manufacturer on a contract basis. Overall, about 95% availability may be expected.

The advantages of the gas turbine may be summarised as:

- Potential operational flexibility in heat:power ratio.
- High reliability permitting long-term unattended operation.
- High-grade heat provided.
- Constant high speed enabling close frequency control of electrical output.
- High power:weight ratio.
- Low cooling water requirement.
- Low foundation loads.

The disadvantages are:

- Limited number of unit sizes within the output range.
- Lower mechanical efficiency than reciprocating engines.
- If gas fired, requires high-pressure supply or in-house boosters.
- High noise levels.
- Poor efficiency at low loadings.

Fig 7 shows a schematic of a typical installation firing natural gas with fuel oil standby and producing site electricity and steam. The energy balance in the form of a Sankey diagram is shown overleaf.

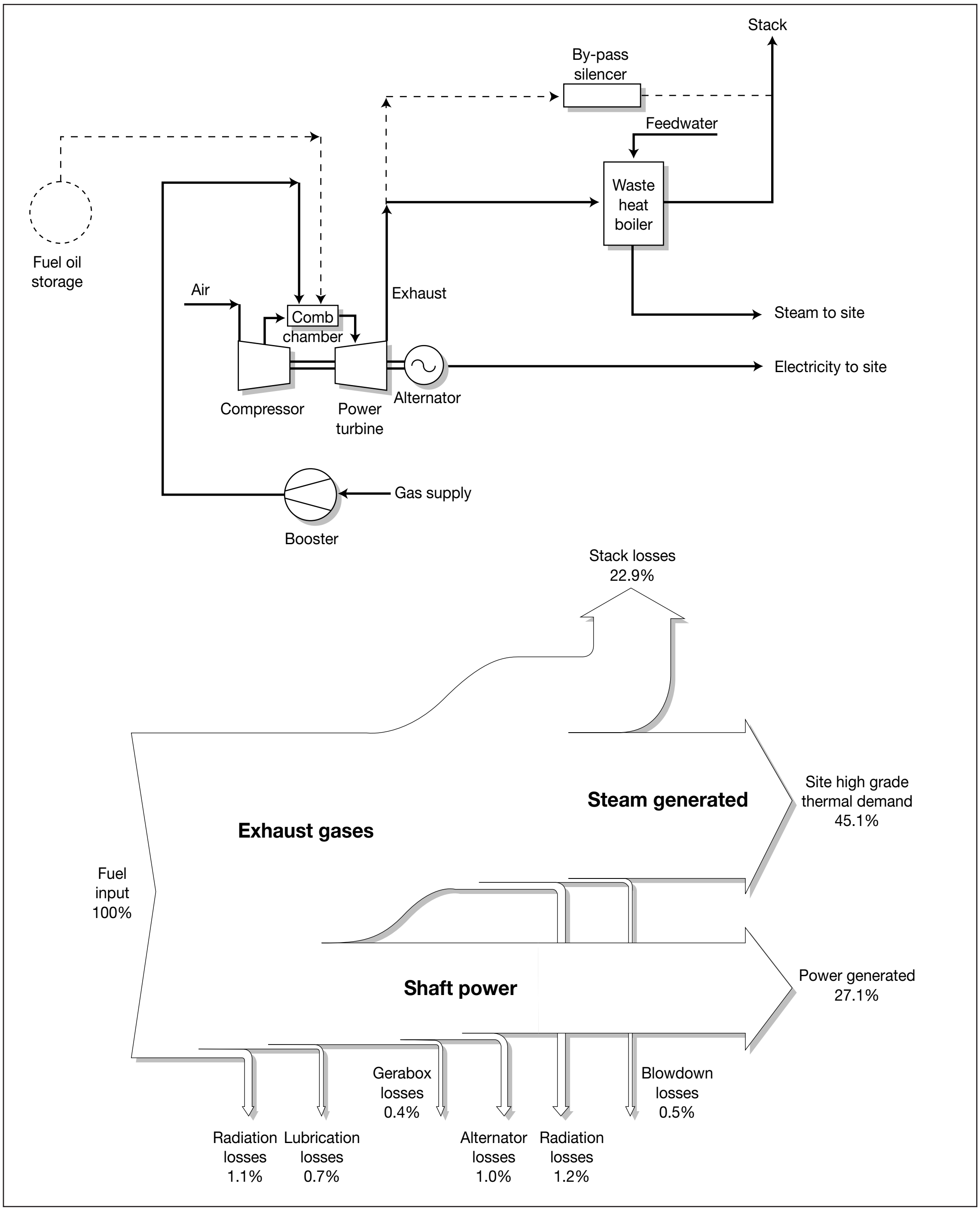


Fig 7 Schematic of typical gas turbine CHP and its energy balance (GCV)

3.3.2 *Reciprocating Engines*

The reciprocating engines used in CHP are internal combustion engines operating on the same familiar principles as their petrol and diesel engine automotive counterparts. Their shaft efficiency is inherently better than that of gas turbines. The usable heat:power ratio range is basically 1:1 to 2:1 and as the exhaust contains large amounts of excess air, supplementary firing is feasible which can raise the ratio to 5:1. However, due to the pulsating nature of the gases, this is comparatively uncommon, although there are installations where the problems have been successfully overcome. Engines and their lubricating oil must be cooled and there is thus, a 'compulsory' supply of heat in the form of hot water at up to 120°C which is produced whether usable or not. Exhaust heat is high-grade at up to about 400°C. Cooling and exhaust heat comprise roughly equal proportions of the total heat produced by the engine. There are two types of engine, classified by their method of ignition as compression or spark.

Compression-ignition (‘diesel’) engines (see Fig 8) for large-scale CHP are predominantly four-stroke, direct-injection machines fitted with turbochargers and inter-coolers. Diesel engines will accept gas oil and can be designed to operate on heavy residual fuel oils and natural gas. The latter is, in reality, a dual-fuel mode, as a small quantity of oil (about 5% of the total heat input) has to be injected with the gas to ensure ignition. As this engine can also run on oil only, it is suited to the interruptable gas tariff. Shaft efficiencies are 35 to 45%. The output range is up to 15 MW_e. Cooling systems are more complex than on spark-ignition engines, and temperatures are lower at typically 85°C maximum, thereby limiting the scope for heat recovery. Exhaust excess air levels are high and supplementary firing is practicable. Compression-ignition engines run at speeds up to 1,500 rev/min. In general, engines up to about 2 MW_e are derivatives of the original automotive diesels, operate on gas oil and run at the upper end of the speed range. Above 2 MW_e, they evolved from marine diesels and are dual-fuel or residual fuel oil machines running at medium to low speed.

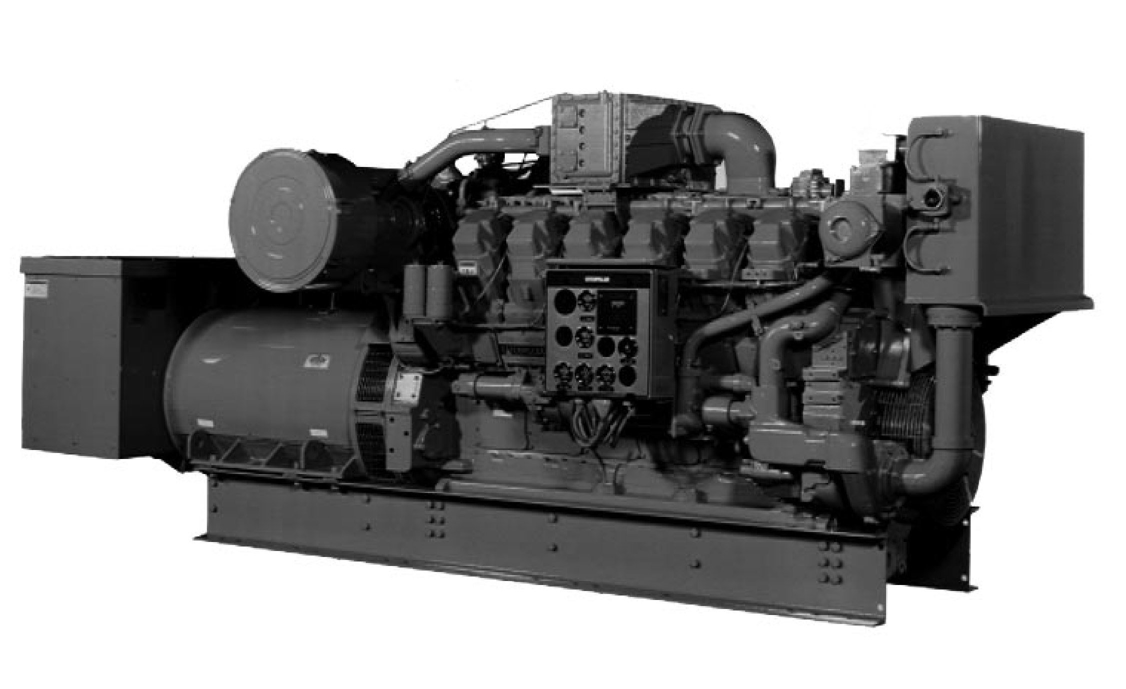


Fig 8 Gas engine prime mover (courtesy of Caterpillar Overseas S.A.)

Spark-ignition engines are virtually all derivatives of their diesel engine equivalents. They generally offer lower capital cost per kW_e than a compression-ignition engine, although shaft efficiency is lower, at up to 35%. A wide range of engine sizes is available, up to a maximum of around 4 MW_e. The engine cooling system typically delivers temperatures in the range 70 - 80°C, although temperatures of up to 120°C can be achieved. Operation at high temperature extends the scope for the use of CHP on site, but will reduce overall levels of efficiency. They are suited to the smaller and simpler CHP installations, often with cooling and exhaust heat recovery cascaded together with a waste heat boiler providing low-pressure steam or medium/low temperature hot water to site. Spark-ignition engines operate on clean gaseous fuels, natural gas being the most popular. Bio and similar recovered gases are also used, but because of their lower CV, give reduced output for a given engine size. Spark-ignition engines give up less heat to the exhaust gases (and correspondingly more to the cooling system) than diesel engines and as a result supplementary firing is rare.

Reciprocating engines produce out of balance forces and require supports and foundations specially designed to absorb the severe vibration effects created. Foundation requirements may be minimised by the use of, for example, pneumatic support systems which effectively transmit the deadweight load only. Noise is marginally less of a problem than with gas turbines, although the low frequency component can have a disproportionately disturbing effect on the human ear. This is more difficult to attenuate and extensive acoustic shielding is required.

Reciprocating machines by their nature have more moving parts, some of which wear more rapidly, than is the case for purely rotating machines, and have running as well as shutdown maintenance requirements. Shutdown maintenance, again usually provided by the manufacturer, is at much shorter intervals, nevertheless, 85 to 92% availability is feasible. Reciprocating engines consume lubricating oil in moderate quantities.

The slower the speed the less maintenance is needed, but engine size and weight increase for a given rating. Maintenance is addressed in Section 3.7.

Figs 9 and 10 show schematics and Sankey diagrams for compression-ignition and spark-ignition schemes respectively.

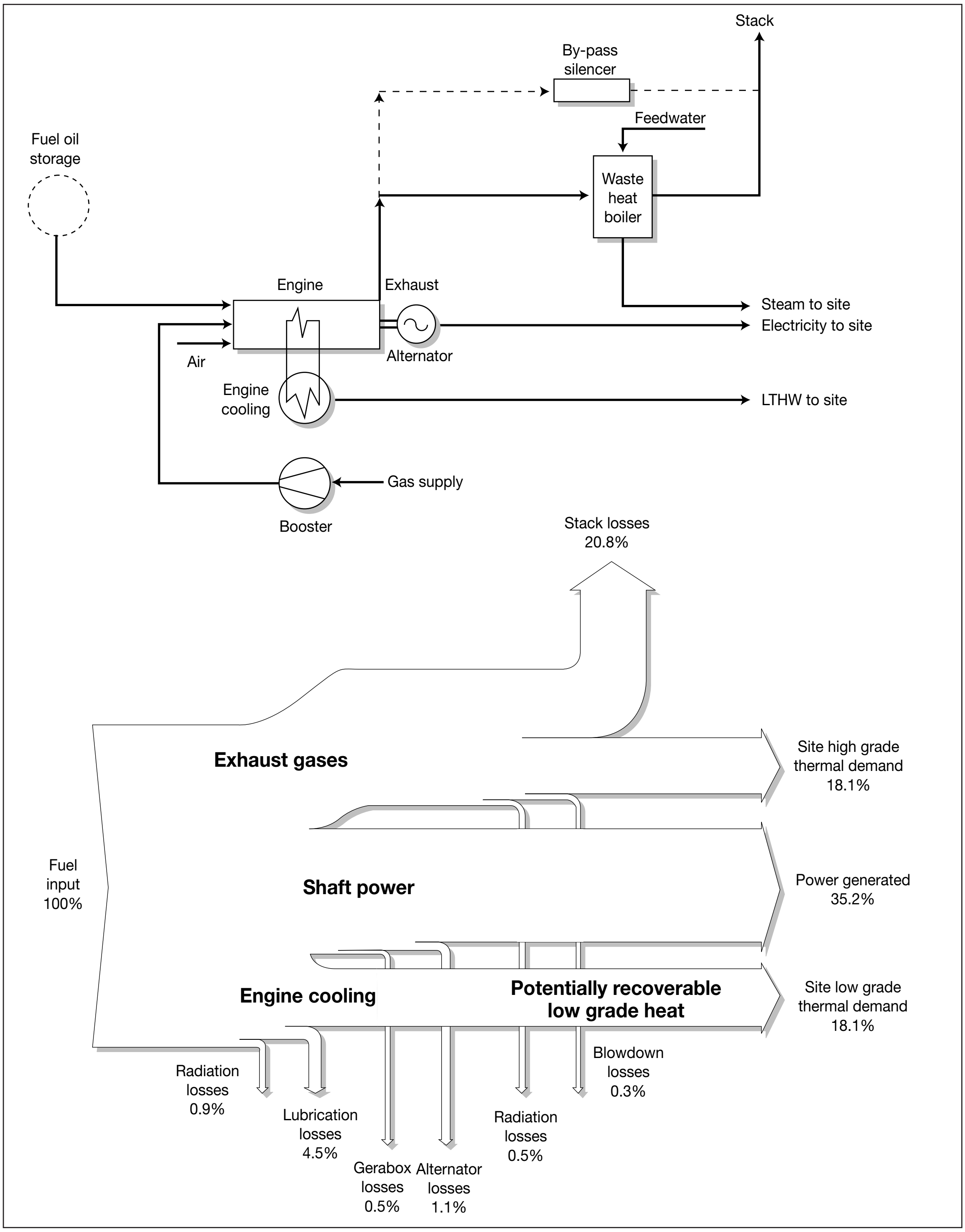


Fig 9 Schematic of typical dual-fuel compression-ignition engine CHP and its energy balance (GCV)

Summarising, the advantages of reciprocating engines are:

- High power efficiency, achievable over a wide load range.
- Wide range of unit sizes.

The disadvantages are:

- Must be cooled, even if the heat recovered is not reusable.
- A large proportion of the heat output is low or medium grade heat from the jacket and lubrication oil cooling.
- Low power to weight ratio and out of balance forces requiring substantial foundations.

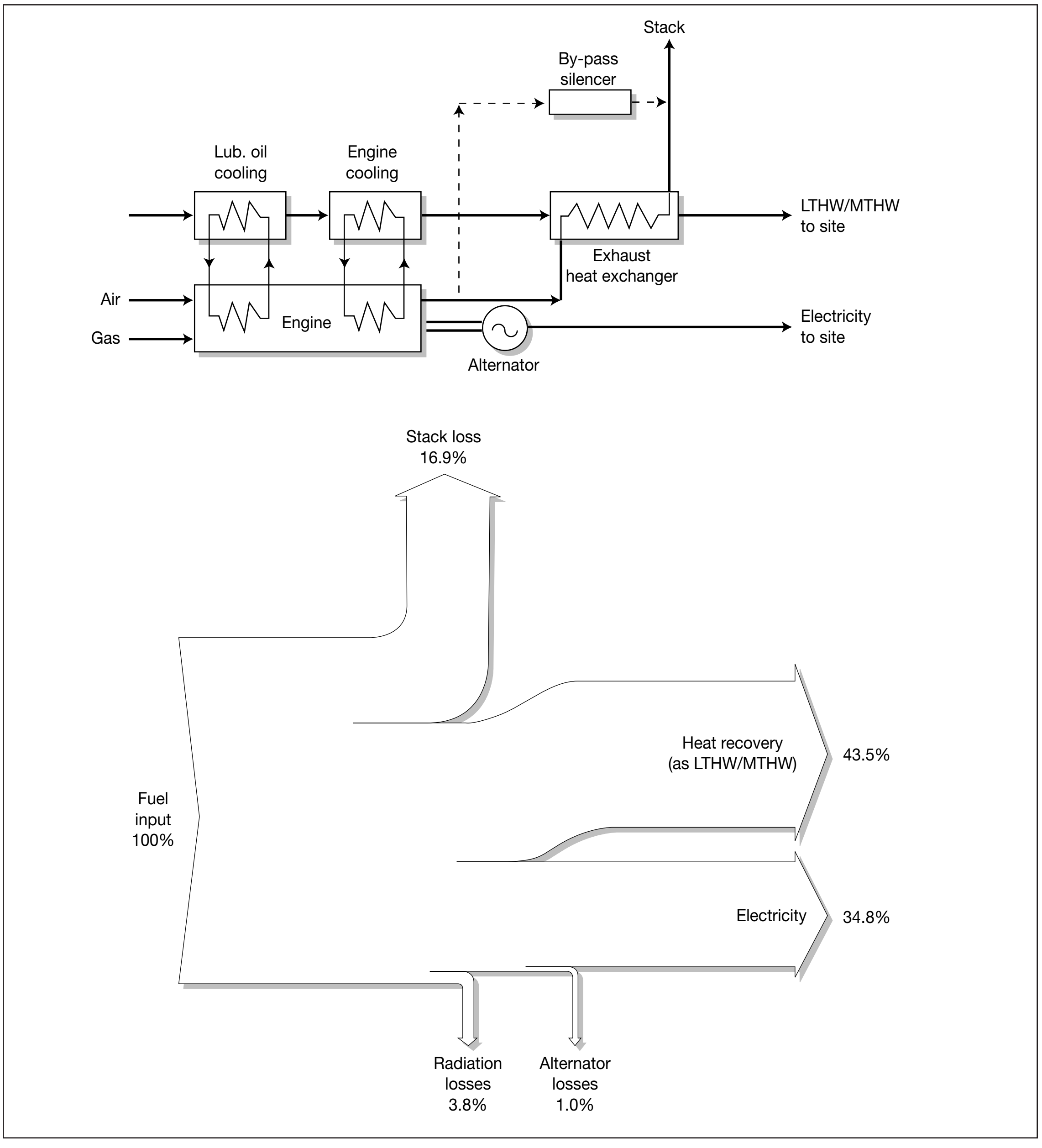


Fig 10 Schematic of typical spark-ignition engine CHP and its energy balance (GCV)

3.3.3 *Steam Turbine*

In the steam turbine, (see Fig 11) one or more sets of blades attached to the turbine rotor are driven round by steam as it expands from high to lower pressure. The power produced depends on how far the steam pressure can be reduced through the turbine before being extracted to meet other site heat energy needs. The simplest arrangement is the back-pressure turbine, where all the steam flows through the machine and is exhausted from the turbine at the pressure required by the site. Where more than one grade of heat is required, the higher grade is supplied by extracting ‘pass-out’ steam at the appropriate pressure part-way along the turbine, the remainder continuing to the exit, thus generating further power, before exhausting to process at the lower pressure. Power output may be maximised by expanding the steam down to a vacuum using a condenser. This produces such low-grade heat that it is not generally useful thereafter. Steam turbine sets are designated by their operating mode(s), e.g. back-pressure, pass-out/back-pressure, and pass-out/condensing.

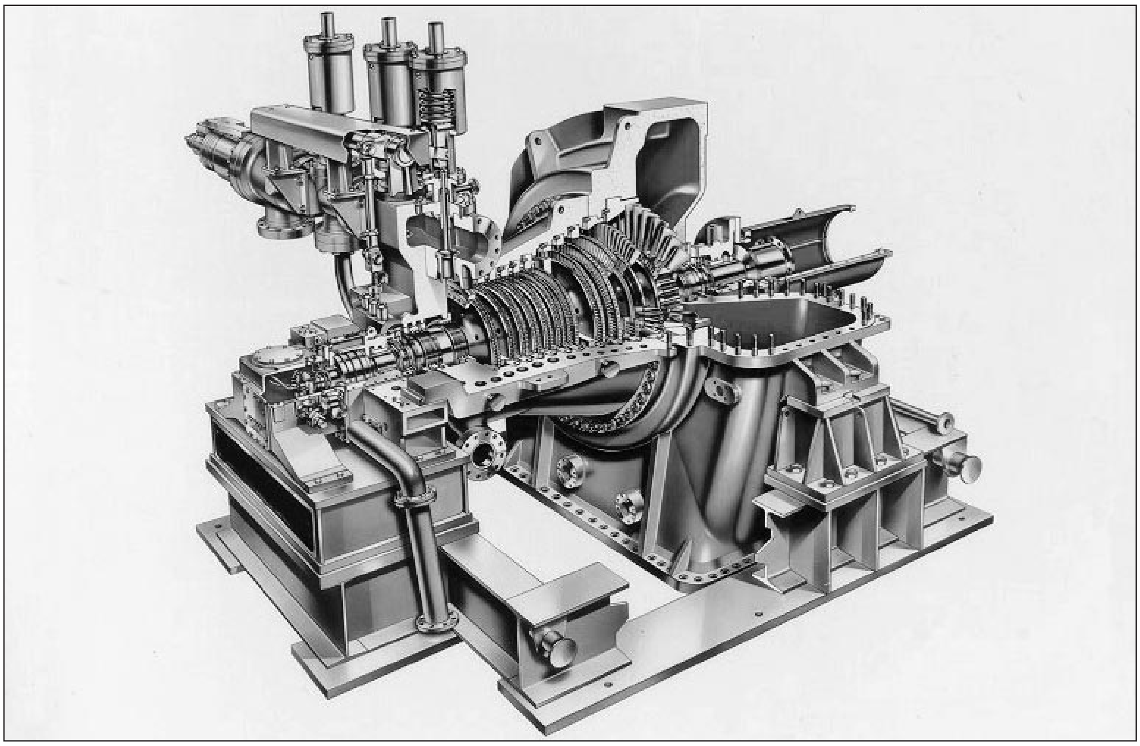


Fig 11 Cut-away image of a steam turbine (courtesy of Allen Steam Turbines)

Because steam turbine CHP only produces significant amounts of power when the steam input is at high pressure/temperature and the heat output is relatively low-grade, the plant is capital-intensive because of the need for a higher pressure steam boiler than might otherwise be required, and its application is more limited than for gas turbines and engines. It is most often applied when a very cheap low-premium fuel is available which can only be used after first converting to steam, and is notably the only prime mover option which can use energy derived from any fuel or from by-product heat from a process (e.g. using steam generated in waste heat boilers, particularly in the chemicals industry). The higher the turbine inlet pressure, the more power is produced, but higher steam pressures entail progressively higher boiler capital and running costs and the optimum is a compromise depending on the size of the plant and the pass-out/back-pressures required.

The increasing use of electricity by industry, often at the expense of reduced steam use, has restricted the application of steam turbines due to the fact that the usable heat:power ratio is unlikely to be less than 3:1 and may be 10:1 or more. Steam turbines share many of the attributes of gas turbines: reliability, high speed, no great out of balance forces to impose undue foundation requirements etc. The noise problem is not as severe as with gas turbines.

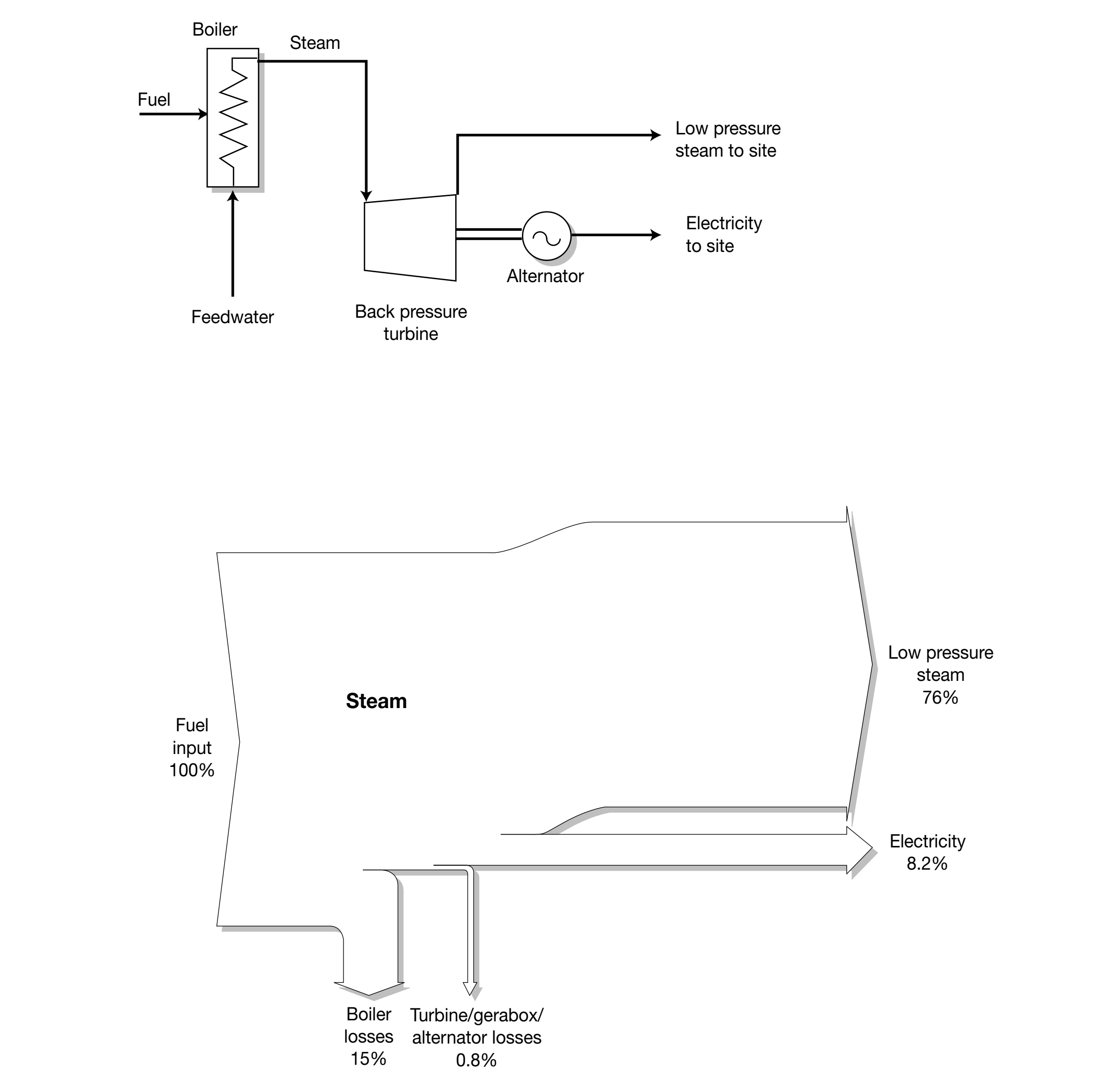


Fig 12 Schematic of back-pressure steam turbine CHP and its energy balance (GCV)

The turbo-generator set is customarily housed in the boiler-house and the building and foundation requirements, for what is effectively a small power station, will be correspondingly extensive. There is no ‘typical’ steam turbine CHP set, as each is very specific to its site conditions. Fig 12 shows a schematic and Sankey diagram for an example where 60 tonnes/hour of steam at 18 bar/330°C is used in a back-pressure turbine exhausting at 2 bar to process, and generating 5 MW of electricity, a heat:power ratio of 9.2:1.

3.3.4 *Combined Cycle*

Single cycle gas turbines provide a high-grade heat output which can be used in processes with a demand for HTHW. On sites where there is no requirement for high-grade heat or where extra electricity is of greater value, the high-grade heat may be utilised in a waste heat boiler to generate steam which in turn may be fed in total or part to a steam turbine to generate additional electricity: the Combined Cycle. It is most often applied to gas turbine sets, which produce the highest grade heat so that steam can be generated at a high enough pressure to maximise steam turbine power and still provide the site with low-pressure steam or its equivalent in the form of hot water. Combined cycles such as this convert 40% or more of the original fuel energy into electricity and if supplementary firing is also employed, provide the most flexible CHP systems currently available. Its application is particularly suited to sites requiring both low and high-pressure steam, as the latter will dictate the selection of a high-pressure boiler plant regardless of the CHP plant. Fig 13 illustrates a typical combined cycle plant in schematic and Sankey diagram form.

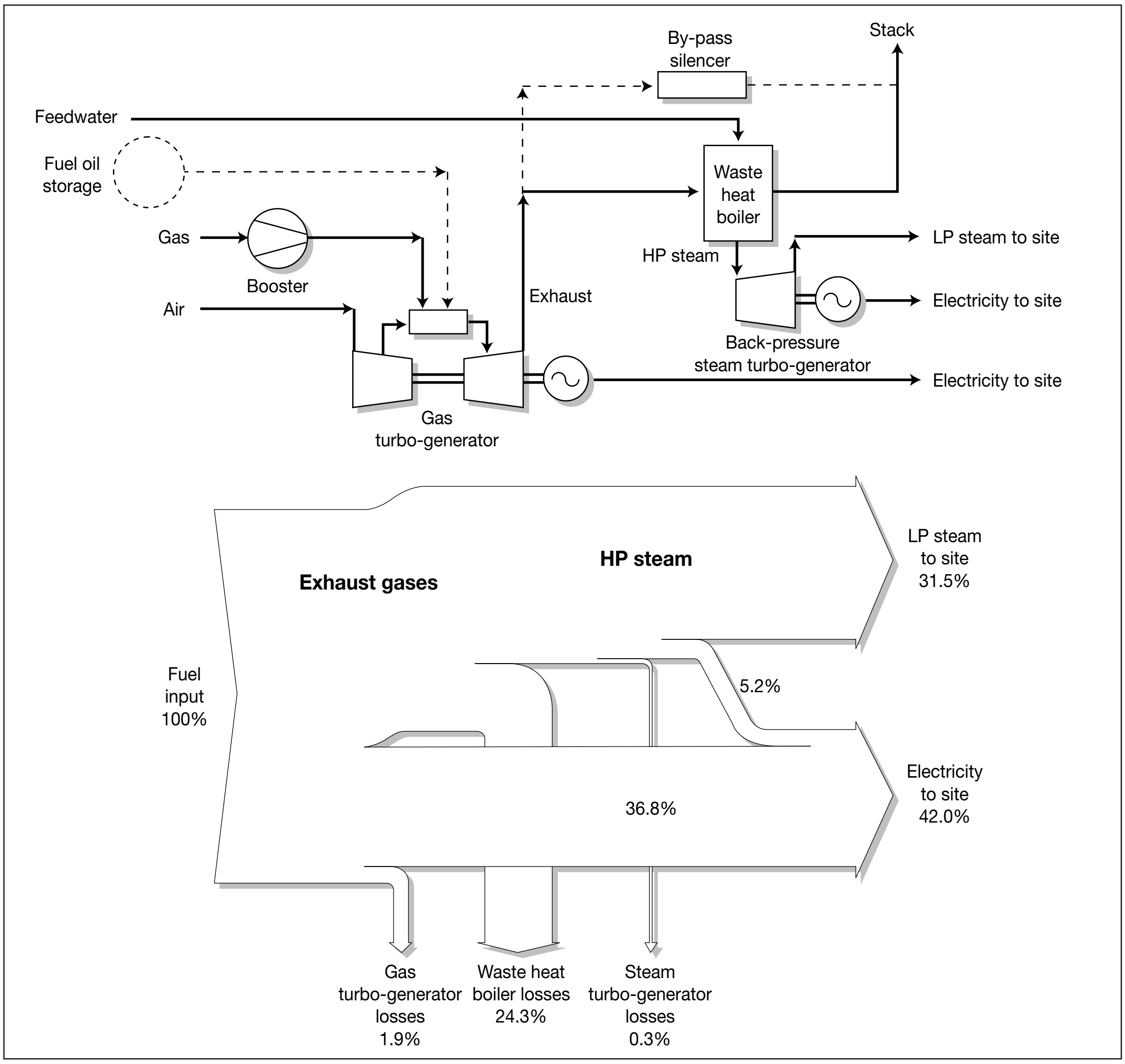


Fig 13 Schematic of combined cycle CHP and its energy balance (GCV)

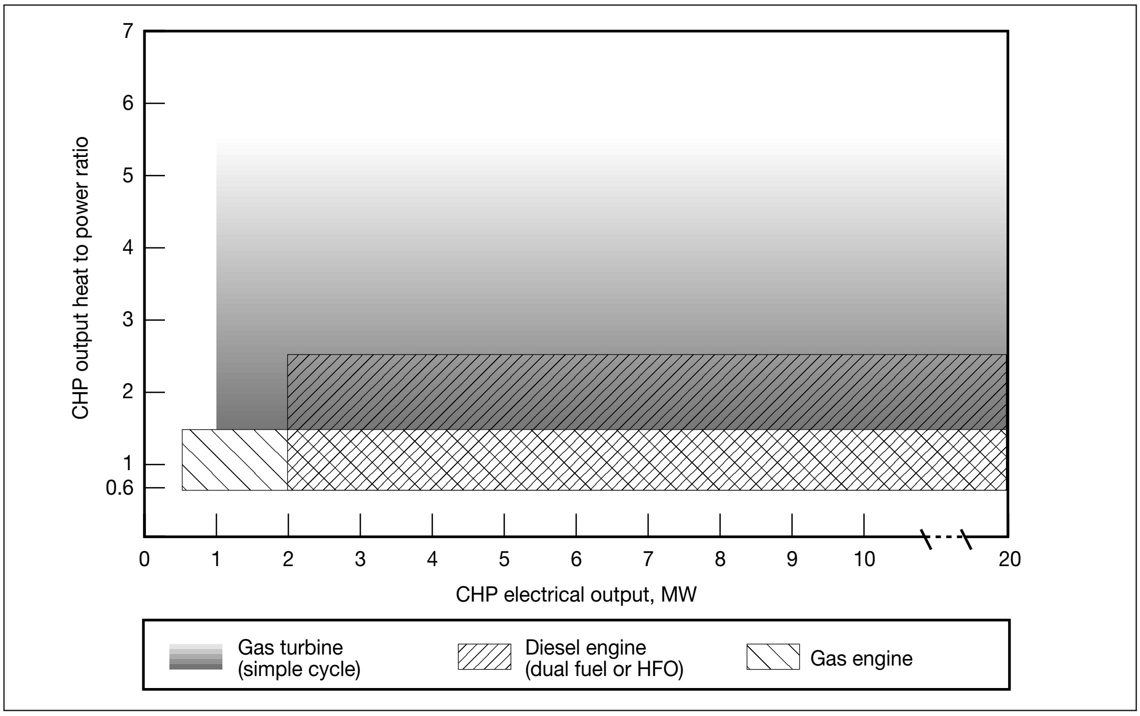


Fig 14 CHP system characteristics for three types of prime mover

Table 3 Summary of prime movers

Type of of plant	Typical output range	Typical fuels	Typical heat:power ratio	Grade of heat output
Gas turbine	0.5 MW_e upwards	Natural gas Gas oil Landfill, bio and mine gas	1.6:1 Up to 5:1 with supplementry firing	High
Compression engine	2 MW_e upwards	Natural gas +5% Gas oil Heavy fuel oil	1:1 to 1.5:1 Up to 2.5:1 with supplementry firing	Low and high
Spark engine	Up to 4 MW_e	Natural gas Landfill, bio and mine gas	1:1 to 1.7:1	Low and high
Steam turbine	0.5 MW_e upwards	Any, but converted to steam	3:1 to 10:1	Medium
Combined cycle	3.5 MW_e	As gas turbine	Down to 1:1	Medium

3.4 Electricity Generation and Distribution

Large-scale CHP generators are three-phase a.c. units, usually 6.6 kV or above, although 415 V may be adopted at the lower end of the range. Transformers are used as required to change the voltage to that required by the site distribution network. With a high-speed prime mover (gas or steam turbine) a step-down gearbox is usually interposed to drive the generator at a speed suitable to its type. The main types are synchronous cylindrical rotor machines running at 3,000 rev/min and salient pole generators, e.g. 4-pole running at 1,500 rev/min. Reciprocating engines are unlikely to be fitted with gearboxes and the generator speed is thus in the range up to 1,500 rev/min, which dictates the application of salient pole machines. It is important to remember that not all of the generator output is available for beneficial use. The CHP plant requires electricity to drive auxiliary pumps, fans etc., and this 'parasitic' load can be considerable, particularly when a low-pressure gas supply has to be boosted or elaborate cooling systems are employed. For example, the auxiliaries for a prime mover/generator set will consume about 1% of the generator output with a gas turbine and 3% with a compression-ignition engine, and if served from a low-pressure gas supply, a further 6% will be required for the gas compressor. Thus, a set rated at 5 MW_e might only deliver 4.55 MW_e of site-useful power and further deductions may be needed for heat recovery plant auxiliaries. Parasitic consumption for steam turbine CHP can be very high, depending on boiler pressure and temperature conditions, possible waste fuel preparation/handling, whether in condensing mode etc.

Every effort should be made at the overall design stage to minimise parasitic use and apply established energy efficiency techniques such as soft-start and frequency/speed controllers for motors as appropriate. The economics of CHP do not depend on the generator terminals output, but on the net electricity available to the rest of the site, a point often overlooked.

Generator ratings are often expressed as the product of voltage and current, i.e. MVA, at a given power factor; a unit rated 3.6 MVA at (typically) 0.8 power factor, for example, would have a ‘useful’ power output of 3.6 x 0.8 = 2.88 MW_e. MVA figures represent the true loadings on cables, switchgear, transformers etc. and are essential for system analysis and design.

There are two basic operating modes: Parallel and Island (or stand-alone). The most common is the parallel mode. This is when the generator is connected to the public supply network, i.e. is running in parallel with the generating company/distribution company system. This enables the import of power to supplement that generated in-house, and, subject to contractual agreement, the export of power surplus to site needs. The public system must be protected against potential malfunctions of the CHP plant which could adversely affect it, and conversely, the CHP plant must be protected from disturbance of the grid. The Regional Electricity Company (REC) will need to be satisfied that the requisite protective controls and procedures are incorporated before accepting parallel operation. These mandatory requirements are presented in the Electricity Association’s Engineering Recommendation G59, further developed in ETR113. Although these documents only cover generating plant up to 5 MW_e at present, the general principles remain valid for the higher power ratings.

Island mode occurs when the CHP plant operates entirely independently of the public supply system. If more than one generator is involved, these may themselves operate in parallel with one another. It is rare for a whole site to be supplied in this way, and it is usually adopted when a discrete part of the site (e.g. a specific processing activity) has its own case for CHP and can be served by a dedicated energy plant.

Island mode most commonly takes place during times of public supply failure, but how much of the site can actually operate under such conditions depends on installed capacity and its characteristics. This potential capability of operating as full or partial standby is a significant advantage of CHP and is often one of the deciding factors in its adoption.

A vital characteristic of a power system is its ability to maintain ‘stability’, i.e. to remain in synchronism when disturbed by conditions such as load changes and system faults. Mention has already been made of the detailed evaluation of site electrical loads in the build-up of the case for CHP. The study should include a detailed analysis of network equipment, operational sequences, load flows, fault levels etc.; a tedious but necessary exercise. The requisite controls and protection equipment can then be designed into the CHP plant. The existing public network and site network may require modifications or reinforcing to suit, and this work should be included in CHP costing.

Fig 15 presents a simplified block diagram of a typical CHP installation with its protection and synchronisation systems.

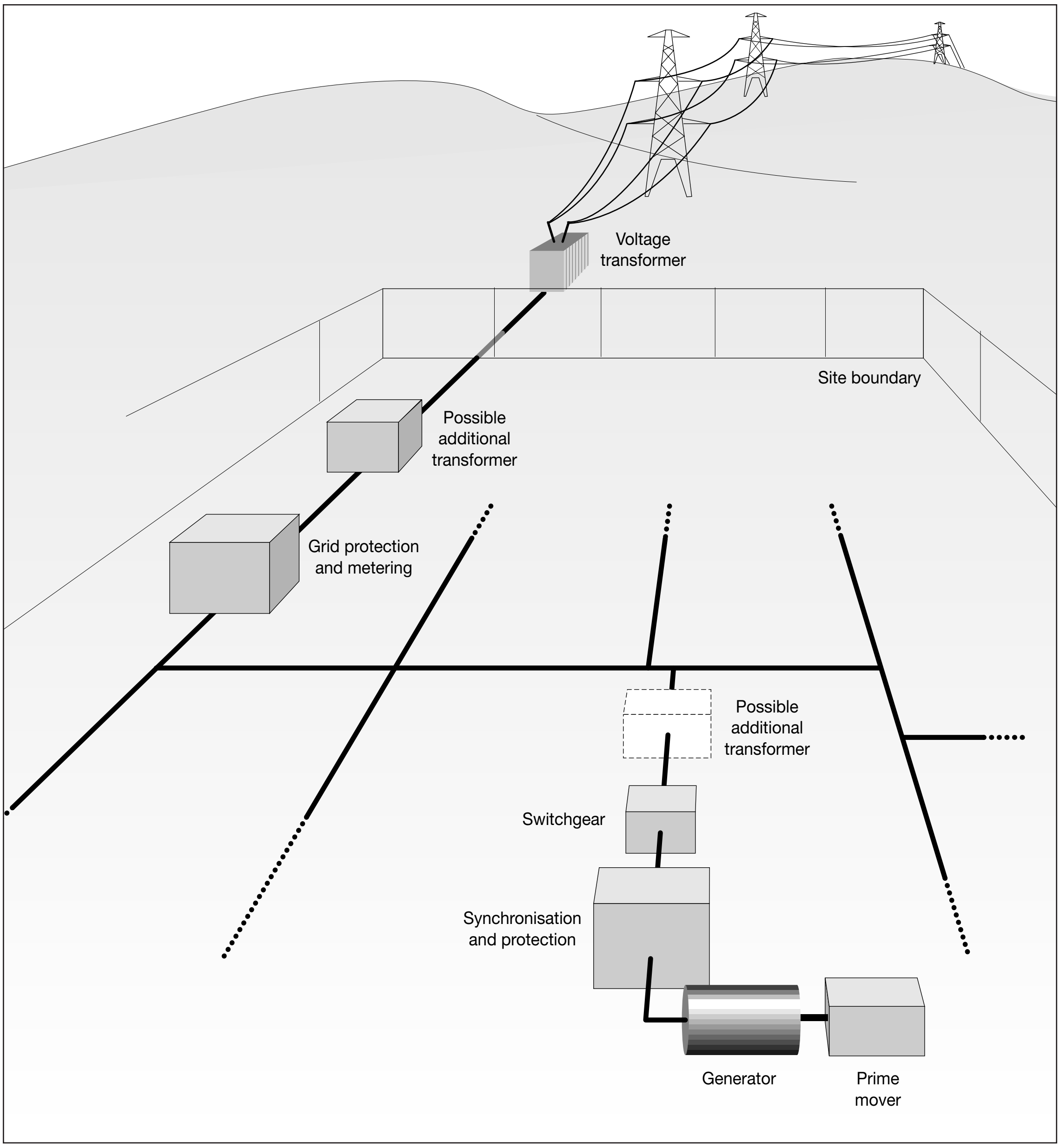


Fig 15 Schematic of typical parallel mode CHP electrical arrangements
(with no electricity export)

3.5 Heat Recovery Equipment

This comprises the plant required for the conversion of CHP heat into the form or forms required by the site, and its delivery to the users. In the most favourable cases, no conversion is required, for example, the use of exhaust gases for drying, or steam turbine output to existing steam networks. Direct use may depend on product sensitivity to combustion gases and may demand the use of premium fuels where susceptible materials are being processed. Engine cooling water could in theory be used direct, for example space heating, but it is desirable for cooling circuits to be self-contained to obviate scaling and corrosion, and the heat is therefore transferred by heat exchangers to separate heating water circuits. In practice, by far the most common heat recovery methods are steam generation from high-grade heat (e.g. combustion products or exhaust gases) and hot water from medium and low-grade heat sources.

Heat conversion and heat distribution must be considered in conjunction; the distance of the user from the CHP plant is crucial and may dictate the choice and number of conversion stages. Gas turbines and engines, for example, can only exhaust against limited back-pressure before suffering a reduction in performance, and direct users and conversion plant must, therefore, be sited close to the CHP plant. Where a centralised boiler plant already exists, the CHP plant will usually be integrated with it. On decentralised sites with widely-dispersed users, CHP heat may be recovered in an adjacent centralised unit, distributed in a single thermally-efficient form such as steam or thermal oil, and re-converted locally to the form required by each user, i.e. hot water, steam, hot air or chilled water. Alternatively, on very large decentralised sites, it may be more beneficial to site multiple CHP units adjacent to the users of the recovered heat. Site heat loads and distribution must, therefore, be carefully analysed to ensure the most practicable and cost-efficient CHP heat recovery system, and to define the true net benefit after deduction of losses.

Effective heat recovery may be considered the essence of successful CHP and accordingly, its implications need to be fully understood.

CHP heat conversion and distribution effectively covers the whole field of heat exchange equipment and heat utility systems, and those most commonly employed are described below.

Engine cooling-water heat is usually transferred via plate or shell-and-tube heat exchangers to low or medium temperature hot water for process or space heating. Extended heat exchange surfaces such as finned tubes may be used for greater efficiency and reduced unit size.

High-grade heat is generally transferred in a type of boiler developed for waste heat recovery and is, therefore, often referred to as a waste heat boiler, although the more appropriate term 'heat recovery boiler' is now widely used. Heat recovery boilers are typically shell-type boilers for low to medium pressure steam (up to 18 bar), medium and high temperature hot water, and thermal oil. For larger boilers (over approximately 20 tonnes/hour steam output) or for higher pressure steam, especially if super-heated to serve, for example, a steam turbine in a combined cycle, a water-tube boiler is normally required. Heat recovery boilers are similar in appearance to their fired counterparts, but are larger for the same duty because there is little radiation heat transfer and friction losses must be kept to a minimum to avoid undue back-pressure on the prime mover exhaust. These differences diminish when supplementary firing is utilised, which requires fuel burners to be fitted to the boiler or in the exhaust gas ducting leading to the boiler.

Supplementary or boost firing uses part of the free oxygen present in the exhaust of gas turbines and compression-ignition engines to burn additional fuel. This requires around 12 to 16% of oxygen to be present. Since no additional air is required for this fuel, there is no increase in the mass of flue gas apart from the added mass of supplementary fuel burnt, so the magnitude of the flue gas energy loss is virtually unchanged. This makes the efficiency when using supplementary fuel greater than that from conventional combustion, typically 88% (gross). This compares well with 80% for the combustion of natural gas in a conventional boiler. Supplementary firing thus improves both the overall cost-effectiveness and flexibility of the CHP plant. The maximum extent of supplementary firing is usually restricted by limitations imposed by the materials or the construction of the heat recovery boiler. With reciprocating engine sets, supplementary firing must be designed to operate satisfactorily with pulsating exhaust gas flow. Supplementary firing is most frequently carried out using in-duct burners, but conventional boiler burners (register burners) may be used in conjunction with water-tube heat recovery boilers.

Auxiliary firing is the provision of an air supply to the supplementary burner to enable the boiler to provide heat energy for the site when the generator set is not running. Thermal efficiency will be lower than for conventional fired boilers because of the design differences mentioned earlier, but this is of marginal significance providing that operation under these conditions is a small proportion of total running time.

Supplementary and auxiliary firing do not inherently require premium fuels, and the economics may be further improved by using a fuel cheaper than that for the prime mover. Although the use of a fuel with a greater fouling propensity, will increase the cost of the boiler.

Supplementary/auxiliary firing entails additional capital cost and this, in conjunction with running cost savings, has to be set against the alternative of maintaining conventional boiler plant under heat for topping-up or standby. A compromise solution is to use a composite boiler. This is sometimes applied in smaller CHP installations, where requirements for additional steam are intermittent. This type typically consists of an unfired waste heat boiler and a conventionally fired boiler combined in a single shell, separately-flued throughout but with the steam/water side common to both. The burner is operated by the control system only when waste heat is insufficient to meet site steam demand.

If the site has large, continuous cooling demands, for example for process or for air-conditioning extensive computer suites, it is worth considering the installation of **absorption refrigeration** plant, which uses heat as its main energy source. Absorption plants typically use water as refrigerant and are ideal for centralised chilled water production, using low-grade heat. Their adoption, incidentally, converts a previous electricity load to a heat load which can materially alter the site's heat:power ratio and thus favourably influence a hitherto marginal case for CHP. The other principal benefit is to extend profitable CHP running time, with some ironing-out of seasonal peaks and troughs.

The efficiency, and hence profitability of the heat recovery system, obviously depends on **maximising heat recovery** from the prime mover exhaust, i.e. on reducing its temperature to as near ambient as possible before discharging to stack. The lower the grade of heat required by site, the lower the potential final exhaust temperature and hence the higher the overall efficiency. This is sometimes achievable by separately meeting a low-grade need using higher grade waste, the commonest example being steam-raising. For example, steam at 10 bar pressure has a saturation temperature of 184°C which limits boiler exit exhaust temperature to about 210°C minimum, but a component of steam production is pre-heated feedwater, typically at 50 to 100°C. This feed water can be heated by an economiser set in the boiler exhaust to achieve a final exhaust temperature of say 120°C, which is a typical design figure for natural gas prime mover/waste heat boiler CHP. If the site can utilise a large quantity of water at about 50°C or below, this can be provided for example, by direct scrubbing of the exhaust in a spray recuperator, and the overall gross thermal efficiency of CHP can then rise to 90% and more. A condensing economiser can be used to acheive higher efficiencies in some cases.

The figures quoted above are for high-premium fuels such as natural gas, contaminants in other fuels may set limits to the extent of exhaust temperature reduction. For example, the SO_x in exhaust gases from sulphur-bearing fuels condenses out as corrosive acids from about 140°C downwards, and this is the lowest practicable limit in most cases.

3.6 Control and Monitoring

The main components of the CHP installation each have their own dedicated control systems with panels which may be local to the equipment or in a control room. The main modules are the generating set(s) comprising the prime mover and generator, and heat recovery equipment, typically a heat recovery boiler. Combustion equipment for supplementary or auxiliary firing interfaces with the boiler control system, although the burners will usually have their own burner management and burner control panels. Other associated equipment such as electrical switchgear, gas compressors, fuel oil treatment, boiler feedwater treatment and supply, may also have dedicated control systems.

The control systems are now usually based on high integrity Programmable Logic Controllers (PLCs) and include all the metering, control and protection systems required for the safe start-up, operation, and normal and shut-down of the equipment. All safety interlocks for emergency shut-down of equipment are normally hard wired between these plant items and their own

control panels. The individual equipment PLCs may be linked to a Distributed Control System (DCS) or a Supervisory Control and Data Acquisition (SCADA) system with Data Processing Units (DPU), data storage, and operator and engineer interfaces located in a main control room.

The DCS may monitor and have full master control of the operation of some equipment, such as electrical switchgear or the boiler (excluding burner management) but with more limited control functions for other equipment, such as the generating set. A SCADA system communicates with equipment PLCs and other control systems and provides a user interface, data storage and connection to other software, such as an optimisation package. Control and monitoring functions, apart from safety interlocks, are transmitted to and from the DPUs via serial links with the local controls.

Performance monitoring is a key function of modern process control systems. Monitoring data is needed to:

- Detect faults, malfunctions, under performance etc, at the earliest possible stage so they can be promptly rectified.
- Enable fine tuning and optimisation.
- Facilitate modifications in order to respond to alterations in site energy loads, new or amended electricity supply tariffs, fuel price/availability fluctuations etc.
- Audit the return on investment.

Optimisation takes the monitoring and control of the CHP system one step further with the objective of maximising the economic benefits of the installation. Optimisation may be on-line, using continuously updated real time data, or off-line, using a snapshot of current or historical data or manual data input. On-line optimisation may be open loop, advisory mode only, or closed loop where the optimiser is allowed to adjust the operating parameters of the CHP system.

The logic to achieve this optimum is not inherently complex. However, because benefit levels can vary markedly over short periods (for example, with changes in site energy demands and heat:power ratios) complexity inevitably builds up. Some benefit variations are external. The price of bought-in electricity is the main yardstick for profitability, and CHP electricity produced during the low-cost periods of time of day and seasonal tariffs is less competitive, as is surplus exported electricity.

3.7 Maintenance

Maintenance of the prime mover is the second biggest component of the operating costs of CHP after fuel purchases, and almost without exception, will require the expertise of the equipment manufacturer or a specialist maintenance contractor for all but the most routine checks.

As with all engines, the prime mover requires regular maintenance and inspection in accordance with the manufacturer’s schedule. Scheduled maintenance downtime for a gas turbine will typically average two-weeks/year, while a reciprocating engine may require five-weeks annual downtime. Unscheduled, breakdown outages are also a fact of life. Manufacturers and specialist contractors offer various forms of long-term maintenance contracts. These range from routine scheduled maintenance only, to a complete maintenance package including engine replacement and guaranteed levels of availability. Some gas turbine manufacturers carry spare engines in stock, enabling a full engine replacement to be achieved with minimum downtime.

The comparative maintenance costs of gas turbines and reciprocating engines are much debated, with the protagonists naturally favouring their own case. There is unlikely to be a consensus until a larger body of CHP operating experience enables a truly realistic assessment of lifetime running costs. However, some guidance can be offered which will permit those considering CHP to include a realistic figure for the additional overall operating and maintenance costs (O&M) in

their evaluation. Table 4 provides indicative maintenance costs, expressed in p/kWh of electricity generated.

Table 4 CHP maintenance costs

Prime mover	**4,500 running hours/year**	**8,000 running hours/year**
Gas turbines	0.4 p/kWh	0.35 p/kWh
Gas engines	0.7 p/kWh	0.6 p/kWh
Dual-fuel compression-ignition engines	0.8 p/kWh	0.7 p/kWh
Steam turbines	less than 0.05 p/kWh	less than 0.05 p/kWh

Two sets of costs are presented, based upon 4,500 running hours/year and 8,000 running hours/year respectively. Costs will vary where running hours are significantly different to these. Costs include all maintenance of the prime mover (including major refurbishment/replacement at the end of its useful life), maintenance of ancillaries (gas compressor, generator etc), consumables, and insurance. Excluded is the (relatively small) cost of maintaining the heat recovery boiler (HRB) which is likely to be balanced by reduced maintenance costs on the existing boilers, fully or partially replaced by the HRB, except in the case of steam turbine or combined cycle CHP, when a high pressure HRB is installed where no high-pressure boilers previously existed.

4. ENVIRONMENTAL ISSUES

4.1 Benefits from CHP

CHP is a highly efficient energy process which can result in overall savings in energy together with significant reductions in combustion products per unit of energy provided at the point of use compared with electricity from conventional power stations and heat from on-site boiler plant. Table 5 shows an illustrative example of the environmental benefits which can be achieved from the installation of CHP. The example considers a CHP unit with a gas turbine and heat recovery boiler, with an overall heat:power ratio of 1.7:1, replacing steam generated in HFO-fired site boilers and electricity from the public electricity supply. The example quoted should not be regarded as typical, since the environmental benefits of CHP will vary depending upon the specification of the new CHP plant and the existing arrangements for energy supply to a site. For all propsed CHP schemes, the actual benefits should be determined on a case by case basis.

Table 5 Example of environmental benefits of CHP based on 1 MWh of electricity delivered to point of use

	Existing energy supply		Gas turbine CHP[3]	Percent reduction due to CHP
	Site boilers	**Purchased electricity[1,2]**		
Primary energy MWh	2.30	2.70	3.76	24.8
CO_2 (kg)	566	727	676	47.7
NO_x (kg)	1.34	1.93	1.20	63.3
SO_2 (kg)	7.21	5.21	0.00	100.0

[1] Assumes 37% overall efficiency for electricity delivered (primary energy basis)
[2] Assumes 50% coal-fired, 45% gas-fired and 5% oil-fired central electricity generation
[3] Assumes 27% electrical efficiency (GCV)

Environmental regulation continues to impose tighter limits on emissions to air from many industrial and other combustion processes. Where existing plant fails to meet current or future emissions limits, abatement equipment may be required in order to ensure regulatory compliance. This equipment often imposes high capital costs, while presenting no opportunity for a financial return. With the correct choice of technology CHP can provide an effective alternative to abatement measures, with the further benefit of a positive return on investment. In such circumstances the case for investment in CHP can be strengthened by regarding the costs of the abatement plant as an avoided cost, which is then offset against the cost of CHP.

4.2 Local Environmental Impact

The installation of CHP in itself has an environmental impact which must be addressed at site level and is subject to statutory controls. The environmental aspects of large-scale CHP are discussed in detail in GPG 116 *Environmental aspects of large-scale combined heat and power*.

The underlying philosophy is to limit to defined levels any nuisance or danger to persons and the environment in the immediate vicinity of the plant concerned and in the general locality. The latest UK legislation, particularly regarding emissions, sets out to match aims to cost-effective technology with a timetable for upgrading using BATNEEC (‘best available techniques not entailing excessive cost’).

The main considerations are atmospheric emissions, noise, safety and the visual impact of the development (planning requirements).

4.2.1 *Atmospheric Emissions*

The main issue is stack emissions which are the products of fuel combustion discharged to atmosphere after they have done their useful work. Potentially harmful gaseous emissions are sulphur oxides (SO_x) from sulphur originally in the fuel, carbon dioxide and monoxide (CO_2, CO) and nitrogen oxides (NO_x). SO_x and NO_x cause acid rain, and CO_2 and CO are associated with the greenhouse effect. In addition, oil and solid-fuel-fired plant produce particulates such as soot, fly ash and grit.
For CHP plant, the applicable limits and the authority responsible for enforcing emission limits depend on the rated capacity of the gas turbine/engine or supplementary firing, expressed as net thermal input (i.e. fuel burning rate at maximum continuous rating multiplied by the net CV, and expressed as MW):

- Up to 20 MW. Local authorities, using Clean Air Act guidelines.
- 20 MW to 50 MW. Local authorities, using Environmental Protection Act limits.
- Over 50 MW. Environment Agency.

CHP schemes with electrical outputs 1 MW_e and above can fall into any of the three categories.

Some waste products pose specific problems - chlorinated plastics in mixed refuse, for example, can result in dioxin and hydrochloric acid emissions. All ‘non-standard’ wastes must be sampled and analysed, test-burnt and the emissions analysed, so that any resultant plant will be designed to confirm to the regulations.

The chimney or stack is environmentally important, because its purpose is to mix the flue gases as rapidly as possible with the general atmosphere, at a height sufficient to ensure that ground level concentrations of pollutants do not exceed specified limits. Stack design must, therefore, give a fast discharge (at least 15 metres/second flue gas velocity) and a height depending on the type of fuel, height of adjacent buildings, nature of the locality etc. Design guidelines are set out in Environment Agency Technical Guidance Note D1.

The storage and handling of solid and liquid fuels, ash and waste should be designed and operated to prevent visible dust emissions, the emission of offensive vapours and gases etc., and provision should be made to contain spillages.

4.2.2 *Noise*

CHP plant and auxiliaries such as gas compressors utilise fast-rotating and reciprocating machines which are extremely noisy. Acoustic shielding may be required to protect operatives in the near vicinity, and the general housing of the equipment should be such as to minimise nuisance to those in the site vicinity. These aims are readily achieveable with the available technology.

4.2.3 *Safety*

CHP plant presents the potential hazards of any process having fuel concentrations, means of ignition, electrical equipment and high speed machines etc. in close proximity. These hazards are all well understood and the technology for their containment fully developed, but they must be taken into account by complying with the standards set either by statute or good practice. These will apply not only to the basic equipment design, but to monitoring/alarm/control systems, area zoning governing electrical equipment, constraints imposed by adjoining production activity, fire prevention and fighting etc. Plant layout, access, operational procedures etc. should be such as to ensure the safety of personnel in the vicinity.

General and specific safety considerations are governed by documents such as:

- Health and Safety at Work Act.
- Electricity at Work Regulations: Approved Codes of Practice, Guidance Notes etc.
- British Standards and Codes of Practice.
- British Gas Guidance Publications.

4.2.4 *Planning*

New buildings and structures will have to meet planning and building regulations requirements, and approvals by the appropriate local authority must be obtained before construction starts. There may sometimes be a conflict of interest to resolve, for example, where a chimney designed to meet emission regulations is deemed to be too high by the planning authority on aesthetic grounds.

In addition to meeting normal local planning requirements, new power generating plant must obtain certain further planning consents prior to construction.

- Section 14 of the Energy Act 1976 - developers of gas-fired plant of 10 MW_e or greater must notify the Secretary of State for Trade and Industry of the proposed project.
- Section 36 of the Electricity Act 1989 - developers of all power plant of 50 MW_e or greater must obtain consent to proceed from the Secretary of State.

The Government White Paper, Conclusions of the Review of Energy Sources for Power Generation, concluded that there should be a stricter consents policy for new power stations, but made a clear exception for CHP plants, recognising that such plants have ‘environmental and other benefits’. This will typically be the case when CHP schemes are properly sized to meet on-site or nearby heat and electricity requirements and deliver high levels of efficiency. However, in order for the Government to decide whether a scheme is ‘properly sized’ under either Section 14 or Section 36, the following information is required from developers:

1. A description of the proposed installation including the combination of turbines and boilers proposed, electrical efficiency and the potential for heat recovery.
2. Operational capabilities, such as electrical import and export arrangements, island-mode operation and back-up fuel capabilities.
3. Details of existing plant to be de-commissioned or maintained as standby.
4. The site’s ***current*** heat and electricity profiles (both daily and annual) including explicitly, base load, peak and average and the duration of these loads.
5. The site’s ***future*** heat and electricity profiles (both daily and annual) including base load, peak and average and the duration of these loads. Evidence of future operating conditions should be provided, especially firm evidence of heat demands.
6. Discussion of the alternatives and implications should consent not be granted (as is currently the case with Section 36 applications).

Provision of this information will assist in ensuring the rapid processing of the application. Details of the specific information required should be obtained from the DTI, Scottish Office, Welsh Office or Northern Ireland Office as appropriate.

5. ECONOMICS

If the technical assessment results in a number of alternative CHP schemes (as is frequently the case) the economic assessment of each one must be prepared before the final choice can be made. During this evaluation, there will be areas of interface with the technical assessment which may itself be modified as a result, and a degree of technical/financial re-iteration is to be expected in order to develop the optimum CHP scheme.

Clearly, if third party financing is being used, detailed capital costs will be someone elses problem, and delivered energy costs over the life of the plant will be the main focus for negotiation.

5.1 System Capital Cost

This is the expenditure required for the establishment of an operational CHP on the site, and comprises:

- CHP unit(s) and associated plant, installed, tested and commissioned.
- Fuel supply, storage and handling infrastructure.
- Reinforcement of local/national electricity networks.
- All associated mechanical and electrical services, installed and commissioned.
- Any new buildings, modification to existing buildings, foundations and support structures.
- Operator training, first set of spare parts and any special tools needed for servicing and repair.
- Engineering design; compliance with planning and building regulations, environmental requirements, fire prevention and protection etc; and external professional services engaged to handle these matters.
- Planning and licensing consents where applicable.

Prices are obtained from the appropriate manufacturers, suppliers and contractors and totalled to arrive at a capital cost. Costs for plant and services which would have been replaced anyway should be identified so that the marginal cost of CHP may be fairly set against its cost savings. Such plant might typically include replacement boilers or new abatement equipment.

The quotations should contain sufficient performance, delivery and cost information to enable:

- Derivation of realistic running costs.
- Production of a provisional programme for the installation.
- Production of a cash outflow programme.

The capital cost estimate will need to be refined as the project progresses:

- Feasibility study - budget quotations for main capital items and factory estimates.
- Equipment/contractor selection - quotations based on formal enquiries and specifications.
- Capital sanction - sanction estimate based on selected suppliers'/contractors' quotations, engineering and project management, other internal costs, commissioning and start-up, training etc. It may be appropriate to include a contingency for items not completely defined at this stage.
- Definitive cost - refinement of the capital cost estimate as detailed engineering and procurement progresses.

5.2 Operating Costs

The annual costs of operating the CHP plant comprise:

- Fuel for the prime mover, and for supplementary and auxiliary firing if applicable.
- Labour for operating and servicing the plant.
- Maintenance materials and labour, including scheduled maintenance carried out by the manufacturers. As some scheduled component replacements are often at long intervals, maintenance costs should preferably be averaged over at least five years to include major refurbishment work.
- Consumables, e.g. lubricating oil, feedwater treatment chemicals, cooling tower dosing, as applicable.
- Other costs, e.g. insurance, rates.

The total of these items after deducting the value of any surplus electricity exported, constitutes the running cost of the CHP plant. Using the manufacturers' performance figures to proportion fuel consumption and hence fuel cost between electricity generation and heat production, and similarly allocating the other costs on a rational basis, total running costs for each energy form and hence cost per unit can be derived. An allowance for performance degradation during plant lifespan should be considered. The analysis will show that the critical cost in CHP economics is the total cost per kWh of electricity generated. The optimum CHP operating strategy required to deliver the maximum cost benefits will be strongly influenced by the electricity tariff structure.

Electricity tariffs are usually maximum demand based or seasonal time of day (STOD). Charges vary according to season and time of day and during off-peak periods, may be cheaper than CHP electricity. CHP is therefore optimised on the basis of only generating electricity when it is profitable to do so. In practice, this may be waived over relatively short periods depending on the flexibility of standby plant. This approach also applies to the export of surplus electricity, which CHP plants tend to have available mostly during off-peak periods; it is pointless to export for a price less than it costs to produce. Again, however, overall economics and site constraints may justify short-term export at a loss. Where the CHP fuel qualifies as 'renewable' and the plant can export electricity under the NFFO at an extremely advantageous price, optimisation would be based on maximising the electricity exported.

5.3 Savings

If the CHP plant provides a relatively small proportion of the site's energy demands and the unit costs of providing the remainder remain unchanged, annual savings are readily derived by subtracting the CHP total running cost from the existing cost of the energy it displaces. The proportion of site energy typically provided by large-scale CHP, however, is such that the costs of providing the remainder are often significantly changed. For example, the reduced amount and different load profile of the residual electricity purchased frequently necessitates a re-negotiated and less advantageous tariff; the reduced and possibly intermittent loading of conventional boilers has a similar effect on heat costs. Use of CHP running costs alone is then insufficient, and comparison of total site energy costs with and without CHP is preferable. Table 6 is a convenient means of presenting the evaluation, the example shown being an edited version of an actual installation.

Table 6 Summary of running costs for one installation

Item	Annual site energy costs £000 Existing	With CHP
Fuel A - existing boilers	2,034	1,550
Fuel B - gas turbine	-	617
Total operating labour and maintenance	250	308
Consumables and miscellaneous	80	88
Electricity purchased	772	146
Electricity exported (credit)	-	(258)
Total energy running costs	3,136	2,451
Savings	-	685

Existing energy costs are compiled from fuel and electricity bills, internal costs records etc., updated if necessary to current price levels. If existing site energy performance is capable of significant improvement by other energy efficiency measures, these should also be appraised as a complementary or possibly competing option to CHP.

The reduction in total site energy costs is the saving due to CHP.

5.4 Sensitivity Analysis

The analysis of costs savings described above necessarily gives a ‘snapshot’ value of the financial benefit and its robustness should be tested by determining its sensitivity to potential variables and risks.

The main variables affecting the energy cost savings and therefore the payback period for an in-house project are:

- CHP operating hours.
- How much of the heat available from the prime mover is used.
- Variations in the prices of fossil fuel, purchased and/or sold electricity.
- Operating/maintenance costs.

Capital cost variations have a directly proportionate effect on payback period.

Any sensitivity analysis should consider the effects of the risks involved, both technical (plant availability, unscheduled maintenance or replacement, under-performance) and financial (changing costs of fuel and electricity, credit for electricity exported, the cost of borrowing, project life).

The revenue from the CHP installation does not vary linearly with operating hours, a disproportionate part of the savings are made in the winter months when electricity prices are greatest.

Fig 16 shows the sensitivity graph for a proposed CHP scheme, whereby the effect on savings (here expressed in terms of simple payback period) of variations from the datum prices of energy can be readily assessed.

The economics are much more sensitive to the price of electricity than to that of natural gas. For example, an increase in natural gas price from 0.6 to 0.66 p/kWh (10%) would extend the payback period from 4.82 to 5.02 years (a 4.1% increase), whereas a 10% increase in the value

of the electricity generated would reduce the payback period to 4.17 years (a 13.5% decrease). A combination of similar increases in both gas and electricity would result in a payback period of 4.32 years (a 10.4% decrease).

Electricity price (4.15 p/kWh unit cost)	Gas price (p/kWh) 0.48	0.54	0.60 (Base case)	0.66	0.72	0.78
	Simple payback period, years					
+20%	3.46	3.56	3.67	3.79	3.92	4.05
+10%	3.89	4.02	4.17	4.32	4.49	4.66
Base case	4.45	4.63	4.82	5.02	5.25	5.49
-10%	5.20	5.44	5.70	6.00	6.32	6.68
-20%	6.25	6.60	6.99	7.44	7.94	8.51

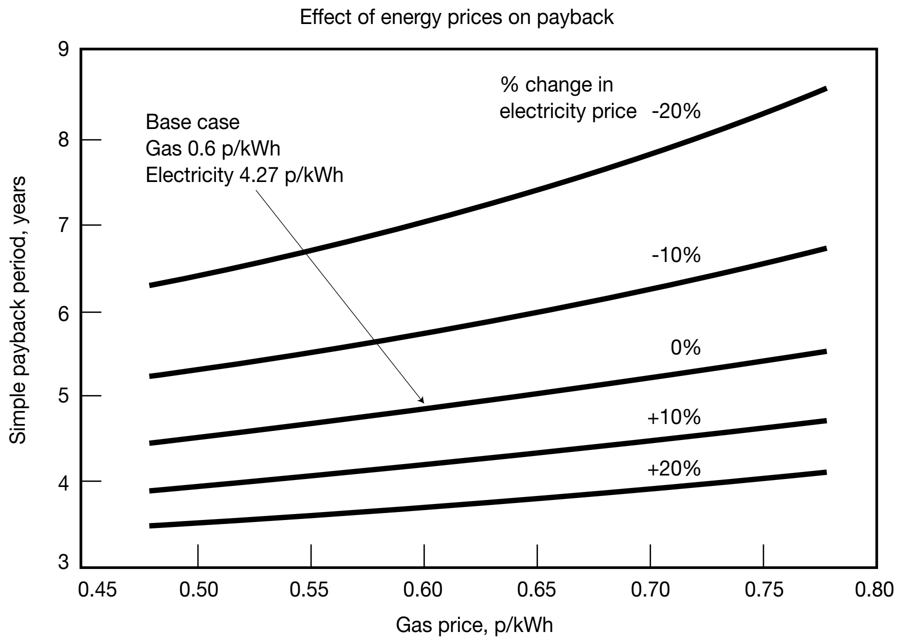


Fig 16 Payback sensitivity to variations in energy prices

5.5 Financing

There are a number of methods of financing a large-scale CHP installation which is likely to represent a relatively major capital project. In general, the commitment to repay the capital cost of a project will not be significantly altered regardless of the funding route. It may, therefore, be argued that the project should be approved only if it meets the corporate financial targets and the choice of funding route should be secondary to the decision to proceed with the project, although this position may be altered by the increasing availability of *energy services* contracts. In deciding on the source of finance, the main considerations are likely to be ownership, risk, and financial benefits in terms of cash flow management and tax efficiency.

5.5.1 *Direct Capital Injection*

If financed by direct capital injection using cash reserves, bank loans or industrial hire purchase, the company retains full ownership and risk. The latter is, of course, offset by the terms of a contract negotiated with a turnkey contractor or through consultants, equipment suppliers and sub-contractors. Although CHP is a long-term investment, it will often have to compete with other potential business projects in a short-term appraisal environment, and so approval for CHP as a self-financed project may prove to be a problem. However, if funding is available, the self-finance route will offer the maximum potential benefits, but the company takes on all residual financial and technical risks beyond those borne by its suppliers. Even with self-financed packages, the actual operation and maintenance can be contracted to an energy services company.

5.5.2 *Finance Leasing*

Finance leasing means that the plant remains the property of the financier while the company undertakes all aspects of its operation and maintenance. This approach may have advantages over self-finance if, through insufficient taxable profits, the company is unable to benefit from the tax allowances available on the capital expenditure. The basis of this arrangement is the payment of regular rentals to the financier over the primary period of the lease, and a peppercorn rent for an optional secondary period. The financier obtains the tax benefits which are passed back, in part, to the user in the form of reduced rentals. In principle, these can be paid out of the savings, thereby assisting cash flow. With this route, the level of financial and technical risk taken on by the company is the same as with a self-financed project.

5.5.3 *Equipment Supplier Finance (ESF)*

With ESF the equipment supplier provides and installs the equipment at no cost. The customer (company) pays for the fuel and agrees to buy the electricity generated at an agreed price linked to some economic indicator. Consequently, the equipment supplier takes most of the technical risk and, in turn, the company’s savings will be significantly lower than under capital purchase. It is normal for the ESF package to include design, installation and maintenance, and the contract period is typically between five and ten years. Under this deal the customer will also carry the risk related to fuel price fluctuation.

The equipment supplier will need to assure themselves of continued income from the sale of utilities to the company for the duration of the contract period. The commitment required may be in the form of a substantial standing charge, a lease payment or a high level of ‘take or pay’ volume for the energy supplied. The latter is a risk of which the customer needs to be aware.

5.5.4 *Contract Energy Management (CEM)*

CEM differs from ESF in that it will usually cover a range of energy services, one of which might be CHP. A CEM company is not normally an equipment supplier, but a service company specialising in the supply, installation and operation of energy plant. Although CEM can be limited to the contracting out of the operation and maintenance of existing facilities, it often includes the design, installation and third party financing of new plant such as CHP. As with ESF, the savings from a CHP plant financed under a CEM agreement will be less than with a self-financed installation, since the CEM company has to recover the cost of the capital investment, its operating costs, and cover its overheads and profit. The advantage to the host site is that the capital and expertise is provided by the CEM company and all of the technical risk and some part of the financial risk is transferred.

It should be noted that CEM and finance are not intrinsically linked and it is possible to enjoy the core benefits of CEM - cost reduction and operational risk transfer - independent of the finance route chosen.

5.5.5 *Energy Services*

An even more integrated and flexible approach to the provision of energy services has developed since the privatisation of the electricity supply industry. It comes from specialist energy companies, most of which either have roots in the electricity or gas supply industries or a CEM background. In addition to the provision of typical CEM services, the energy services company may take responsibility for fuel purchasing. Their position in the energy markets may enable them to negotiate better contracts than their clients can on their own. In addition, on new sites or for major refurbishments much, if not all, of the energy infrastructure may be provided under contract with an energy services company. Such an arrangement enables the host company to concentrate effort and resources on its core business activities, while out-sourcing its energy supplies to a power plant built by a third party on or adjoining its premises. Capital costs and risks may be shared between the two parties.

More detailed guidance can be found in GPG 220 *Financing large-scale CHP for industry and commerce*.

5.6 Financial Analysis

Financial analysis or appraisal is the evaluation of CHP savings against capital required, i.e. the return on investment, according to criteria defined as company investment policy and frequently in competition with other investment opportunities.

There are three commonly-used appraisal methods: simple payback, internal rate of return and discounted cash flow. Financial analysis is covered in GPG 220 *Financing large-scale CHP for industry and commerce* and GPG 227 *How to appraise CHP – A simple investment appraisal methodology*.

6. CHP IN ACTION

CHP has a very long history, and indeed, is virtually standard in the larger factories of the paper and chemical industries which have large concurrent power and heat demands. During the 1980s, the range of available prime movers expanded considerably, giving far more choice of heat:power ratios, greater flexibility and reliability. This, coupled with support and promotion from Government and other bodies, has lead to the growth now seen in industry. CHP has been successfully applied in many sectors of industry including:

- Petrochemicals.
- Paper and board manufacture.
- Pharmaceuticals and fine chemicals.
- Brewing.
- Food processing.
- Bulk chemical processing.
- Confectionery.
- Hospitals.
- Textiles processing.
- Sewage treatment.
- Large hotels and leisure complexes.
- Airports.
- Communal heating.
- Animal feeds.
- Engineering.
- Horticulture.

And many more.

Case Studies are available describing installations at many of these types of plant, as well as Guides addressing many technical and economic aspects of CHP and energy efficiency in general.

Call the

Environment and Energy Helpline
on freephone 0800 585794

and ask for a copy of the Industrial and/or Buildings CHP publications list(s).

APPENDIX I

CONVERSION FACTORS

SI Units

The SI (Systeme Internationale) unit of energy is the joule. Large quantities are expressed as multiples indicated by the following prefixes.

Factor	Prefix	Symbol
10^3	kilo	k
10^6	mega	M
10^9	giga	G
10^{12}	tera	T
10^{15}	peta	P
10^{18}	exa	E

Conversion Factors for Energy Units (multiply by)

from \ to	Btu	joule	kWh	therm
Btu	1	1.055×10^3	0.2931×10^{-3}	10×10^{-6}
joule	0.948×10^{-3}	1	0.2778×10^{-6}	9.48×10^{-9}
kWh	3.412×10^3	3.6×10^6	1	34.12×10^{-3}
therm	100×10^3	105.5×10^6	29.31	1

Comparing Commercial Fuels in Terms of Gross and Net CV

Fuel	Ratio of gross / net CV
Natural gas	1.109
Gas oil	1.067
Heavy fuel oil	1.060
Bituminous coal	1.040*

* Depends on moisture content as fired

Typical Properties of Selected Fuels

Fuel	CV as normally expressed		Contaminants %		
	Gross	**Net**	**Sulphur**	**Water**	**Ash**
Steam coal	30.6 MJ/kg	29.7 MJ/kg	1.0	10.0	8.0
Wood waste	15.8 MJ/kg	14.4 MJ/kg	0.4	15	Trace
Heavy fuel oil	41.2 MJ/l	38.9 MJ/l	2.5	0.3	0.04
Gas oil	38.3 MJ/l	36.0 MJ/l	0.2	0.05	0.01
Natural gas	38.0 MJ/m^3	34.2 MJ/m^3	–	Trace	–
Landfill gas	20.0 MJ/m^3	18.0 MJ/m^3	Trace	Trace	–
Mines gas	21.0 MJ/m^3	18.9 MJ/m^3	Trace	5.0	–

Other Conversion Factors

1 ton = 1.016 tonne

1 lb = 0.4536 kg

1 gallon = 4.546 litres

APPENDIX II

GLOSSARY OF TERMS

The definitions given here relate specifically to the CHP context. Terms may have broader or alternative meanings in other contexts.

Absorption Refrigeration

Refrigeration plant which uses heat instead of electricity as its principal energy source, and utilising, for example, water as a refrigerant and typically operating as a chiller unit serving air-conditioning and process cooling. Water vapour from the evaporator is absorbed in a substance having strong affinity for it (e.g. lithium bromide), from which it is separated by heat (generator), condensed and re-admitted to the evaporator. The refrigeration (chilling) effect takes place in the evaporator, which is a tubular heat exchanger where heat is removed from the circulating chilled water system to provide the latent heat to evaporate the refrigerant. Minor amounts of electricity are required for solution and cooling water pumping.

Alternator

A machine whose shaft is driven by an engine or turbine and converts mechanical energy into alternating current (a.c.) electricity. More usually called a generator.

Auxiliary Firing

The burning of fuel (with its own air supply) on waste heat boilers when the generator set is not running but the site heat supply is to be maintained.

Bar

A unit of pressure measure, equivalent to approximately 14.5 lbf/in^2 or 1 atmosphere. (lbf/in^2 is commonly, although less accurately, expressed as lb/in^2 or p.s.i.g.)

Back-pressure Steam

The steam exhausting from the low-pressure end of a steam turbine.

Calorific Value (CV)

The heat available from a fuel when it is completely burnt, expressed as heat units per unit of weight or volume of the fuel. See Section 3.2.3 for details of gross and net CV.

Cascade Control

A system which automatically starts up or stops units in a predetermined sequence to meet variations in the energy demands being served. The sequence may be changed periodically to ensure that the running time of each unit is approximately equal.

Chemical Dosing

The addition of conditioning chemicals to boiler feedwater or cooling water to protect plant from scaling, blocking, corrosion etc.

CO, CO_2

Carbon monoxide, carbon dioxide respectively. Oxides of carbon produced by fuel combustion. CO represents incomplete combustion and can be burnt to CO_2 which is complete combustion.

Compression-ignition

System used in reciprocating engines whereby fuel is injected after compression of the air and is ignited by the increased temperature caused by compression. As pre-ignition is thereby eliminated, higher compression ratios than with spark-ignition engines can be utilised, with corresponding high energy conversion efficiency.

Condensing Steam Turbine

The steam turbine mode whereby steam surplus to site requirements is expanded to the lowest practicable pressure (vacuum stage) to generate more electricity, then exhausted to a condenser where the latent heat in the exhaust steam is removed by cooling water and the resulting condensate is returned to the boiler.

Cylindrical Rotor Generator

A type of electricity generator. As frequency depends on the speed multiplied by the number of pole pairs, higher speeds require fewer poles. In the cylindrical rotor generator, the exciting winding can be accommodated in radial slots machined into the periphery of the rotor.

Demand, Maximum Demand, Demand Profile

The rate at which energy is required, expressed in kW or MW. It is usually related to a time period, typically half an hour, e.g. 1 kWh used over half an hour is a demand rate of 2 kW. Maximum demand is the highest half hourly rate at which electricity is required during a month or year. Peak load or peak demand are the terms usually used for heat energy. A graph of demand rate over a typical day, for example, is the demand profile.

Diesel Engine

Takes its name from the famous German engineer Rudolf Diesel. A generic term for compression-ignition reciprocating engines, whatever the fuel used.

Discount Factor

The factor used to convert net annual cash flow to Present Value, depending on the interest rate and the number of years from present. Calculated by a derivation of the compound interest formula:

$$DF = \frac{1}{(1 + r/100)^n}$$

Where r = % interest rate and n = no. of years from now.

Dual-fuel

The use of two fuels in a prime mover or boiler. They may be alternatives, e.g. with one as standby if the main fuel supply is interrupted, or simultaneous, e.g. in dual-fuel compression-ignition engines, gas plus a small proportion (approx 5%) of diesel is used (the function of the diesel is to reduce the auto-ignition temperature to enable the engine to run essentially on gas).

ETR113

An Electricity Association publication: Engineering Technical Report No. 113 Revision 1 (1995): 'Notes of Guidance for the Protection of Embedded Generating Plant up to 5 MW for Operation in Parallel with Public Electricity Suppliers' Distribution Systems'. Available from the Electricity Association, Engineering & Safety Division.

Excess Air

Reciprocating engines and gas turbines have to operate with far more air than is needed purely for the combustion of the fuel. This excess over the minimum theoretical requirements for complete combustion forms the major proportion of the exhaust gases and is termed excess air.

Fault Level

The maximum prospective current that can flow under a 3-phase short circuit condition. It should be noted that it can vary according to the point in the system at which the fault occurs. The magnitude of the fault level has a major influence on the choice and design of the equipment to be used.

Frequency

The number of times per second that alternating current changes direction. Frequency is expressed as cycles/second or Hertz (Hz) of alternating current. The public electricity supply in the UK is 50 Hz.

Feedwater Treatment

The conditioning of water to make it suitable for use in boilers and associated systems. It is specific to the composition of the water on-site, type of boiler plant etc. and usually comprises some form of softening plus dosing.

G.59/1

An Electricity Association publication: Engineering Recommendation G59/1 1991 'Recommendations for the Connection of Embedded Generating Plant to the Public Electricity Suppliers' Distribution System'. Available from the Electricity Association, Engineering & Safety Division.

Generator

An alternator or a d.c. generator. 'Generator set' refers to the combination of prime mover and generator.

Heat Exchanger

A device in which heat is transferred from one fluidstream to another without mixing. There must obviously be a temperature difference between the streams for heat exchange to occur. They are characterised by the method of construction or operation, e.g. shell-and-tube, plate, rotary.

Heat Grade

A classification of heat source or heat requirement according to temperature. Up to 90°C would generally be classed low grade, otherwise grade limits vary according to the context. Typically, medium grade would be about 90 to 150°C and high grade 150°C upwards.

Heat:Power Ratio

The amounts of heat energy and electricity produced by a CHP unit, expressed as a ratio. There is no agreed standard for its derivation and figures vary depending on whether gross or net CV of the fuel is used for example, or heat output is total or that part which is used. When assessing prime movers, it is therefore essential that a consistent method is employed. Figures in this Guide are based on gross CV and typically usable heat output.

High Temperature Hot Water (HTHW)

Pressurised hot water at 150 to 200°C used for space heating and/or process.

In-duct Burner

A burner comprising an arrangement of fuel nozzles located within a duct along which the combustion air (or oxidant) flows. The fuel nozzles may have their separate supply of cooling or stabilising air. This arrangement is commonly used for supplementary firing of additional fuel using the residual oxygen in gas turbine exhaust as oxidant to boost the exhaust gas temperature before it enters the heat recovery boiler.

kV

Kilovolt = 1,000 volts.

kW, kW$_e$

Kilowatt, kilowatt electric respectively. kW is used to express energy rate of production or demand, whatever the energy form entailed. kW$_e$ is specifically electricity, used for example, to describe the generating capacity of a CHP set.

Load Factor

The average intensity of usage of energy producing or consuming plant expressed as a percentage of its maximum rating. Weekly load factor, for example, would be:

$$\frac{\text{(total output or consumption x 100)}}{\text{(maximum hourly rating x 24 x 7)}}$$

Low Temperature Hot Water (LTHW)

Hot water at up to 100°C used for space heating and low temperature process.

Medium Temperature Hot Water (MTHW)

Pressurised hot water at 100 to 150°C used for space heating and process.

MJ, GJ

Megajoules, gigajoules respectively. Units expressing quantity of heat energy. One GJ is roughly equivalent to 10 therms or 280 kWh.

MW, MW$_e$

Megawatt, megawatt electric respectively. As for kW, kW$_e$, but 1 MW = 1,000 kW.

Network

The distribution system which links energy production to energy usage. Mostly applied to electricity.

NFFA

Non Fossil Fuel Agency, which co-ordinates the purchase of privately generated electricity from renewable energy sources. Under the terms of the 1989 Electricity Act, Public Electricity Supply companies are obliged to purchase this exported power at a price designed to encourage the use of renewables. The extra cost of these purchases is recovered through the fossil fuel levy.

NO_x

A general term for oxides of nitrogen produced by fuel combustion, eventually discharged to atmosphere and considered deleterious emissions harmful to the environment.

Parasitic

Adjective for the electricity used within the CHP plant itself and therefore reducing the amount available for beneficial use.

Particulates

Particles of solid matter, usually of very small size, derived from the fuel either directly or as a result of incomplete combustion and considered deleterious emissions.

Pass-out Steam

Also called extraction steam. Steam taken off part-way along a steam turbine to serve a requirement for that particular pressure, the remainder remaining in the turbine to the exhaust stage to generate more power. There may be more than one pass-out tapping to serve differing site requirements.

Power Factor

kW (MW) divided by kVA (MVA), stated for a given point in an a.c. electricity network, e.g. the incoming REC supply to a consumer. REC tariffs usually have a direct or indirect penalty charge for poor power factor (say below 0.95), which can be avoided by installing power factor correction equipment.

Premium

A general term to describe the quality of a fuel in terms of handling/storage, combustion, consistency of composition, pollutants etc., e.g. natural gas is high-premium, heavy fuel oil is low-premium. Fuel price usually follows premium value.

Programmable Logic Control (PLC)

A programmable device for the control of a system according to a pre-determined logic.

Reciprocating Engine

Strictly speaking, all prime movers are engines. When the mechanical power is produced by the to-and-fro (‘reciprocating’) movement of a piston within a cylinder, machines are so called to distinguish them from purely rotating machines like turbines.

Register Burner

A burner design incorporating a combustion air (or oxidant) regulator known as an air register. The register permits the amount of air to the burner to be controlled and is designed to ensure effective mixing of the air and fuel to give stable combustion and the desired flame shape. (Compare with in-duct burner, commonly used for supplementary firing.)

Salient Pole Generator

A type of electricity generator. As frequency depends on speed multiplied by the number of pole pairs, lower speeds require more poles than can be accommodated within the rotor periphery. In the salient pole generator the exciting winding is formed with copper strip or coils of wire attached to the surface of the rotor.

Sankey Diagram

Named after its originator, a diagram demonstrating graphically and in true proportion, the energy flows in a system, starting with the energy sources (inputs) and showing losses, heat exchange loops etc. to the degree desired. There are several Sankey diagrams in this Guide.

Shaft Efficiency

The percentage of its initial energy supply that a prime mover delivers as mechanical energy at its output shaft. Note: check whether gross or net CV is used to calculate input energy, manufacturers normally use net CV.

Shell-and-tube Heat Exchanger

A unit having a bundle of tubes contained in a cylindrical shell. One fluid flows through the tubes, the other through the shell.

Shell Type Boiler

A cylindrical steam, hot water or thermal oil boiler, usually horizontal but may be vertical. The shell contains water or oil which is heated by the burner flame and combustion products in a tubular combustion chamber called the furnace tube, followed by tubes called convection tubes or annular flueways inside the shell. Sometimes called a firetube boiler or package boiler. A typical shell boiler is in fact, a specialised shell-and-tube heat exchanger.

Soft-start

A technique for starting a motor from rest which reduces the maximum current drawn during start up.

SO_x

A generic term for oxides of sulphur produced by the combustion of sulphur in the fuel, and considered as deleterious emissions. Their presence in flue gases can restrict thermal efficiency, because if the flue gas temperature is reduced below specific levels, highly corrosive sulphurous and sulphuric acids are deposited on heat exchange surfaces and in the chimney.

Spark-ignition

A reciprocating engine which utilises an electrical spark to ignite the compressed air/fuel mixture in the cylinders.

Superheated Steam

Steam whose temperature has been raised above the saturation temperature corresponding to its pressure. This is done almost exclusively to improve its power generating capacity when used in a steam turbine.

Supplementary Firing

The firing of additional fuel in the CHP heat recovery unit, utilising the hot oxygen present as excess air in the prime mover exhaust gases.

Synchronism

The condition whereby generator frequency and voltage levels match those of the public supply. When operating in parallel mode, it is obligatory to maintain these levels within closely specified limits.

Thermal Oil

A mineral oil used as a heat carrying medium in preference to water or steam. Its major advantage is that high temperatures (up to 300°C) are feasible at pressures far lower than would be needed for steam.

Transformers (Voltage)

A device with primary and secondary windings to convert the voltage of electricity from one value to another. Transformers may be step-up or step-down, i.e. voltage increased or reduced, and there may be more than one secondary tapping to give a choice of output voltage.

Water Tube Boiler

The converse of a shell type boiler. Box-shaped, the enclosure acts as a combustion chamber and flueways. Water or thermal oil flows inside tubes arranged in panels around the walls of the combustion chamber (radiant tubes) and in tube bundles in the flue gas stream (convection tubes). The tubes are connected to one or more cylindrical drums which act as water reservoirs and/or steam seperators. If superheated steam is required, saturated steam passes from the steam drum to a tube bundle mounted in the high temperature zone and then out to the steam turbine. Economiser tube bundles which preheat the boiler feedwater to the boiler are used to maximise heat recovery from the flue gases.

APPENDIX III

SOURCES OF FURTHER INFORMATION

Further information on specialist companies involved in the CHP field, including consultants, turnkey contractors and CEM companies may be obtained from:

Association of Consulting Engineers (ACE)
Alliance House
12 Caxton Place
Westminster
London SW1H 00L
Tel: 0171 222 6557

Chartered Institution of Building Services Engineers (CIBSE)
222 Balham High Road
Balham
London SW12 9BS
Tel: 0181 675 5211

Combined Heat and Power Association (CHPA)
Grosvenor Gardens House
35/37 Grosvenor Gardens
London SW1W 0BS
Tel: 0171 828 4077

Electricity Association
30 Millbank
London SW1P 4RD
Tel: 0171 963 5700

Energy Systems Trade Association
Palace Chambers
41 London Road
Stroud GL5 2AJ
Tel: 01453 767373

Institute of Energy
18 Devonshire Street
Portland Place
London W1N 2AU
Tel: 0171 580 7124/6

OFFER
Hagley House
Hagley Road
Birmingham B16 8QG
Tel: 0121 456 2100

LIST OF SOME UK MANUFACTURERS AND SUPPLIERS

This list is intended as a guide only for plant within the range of this Guide and is not exhaustive. Inclusion or omission of a supplier from this list does not imply any comment on their fitness to supply equipment. The list is divided into:

1. Gas Turbines
2. Reciprocating Engines
3. Steam Turbines
4. Waste Heat Boilers
5. Gas Compressors
6. Absorption Chillers

Some companies may supply equipment under more than one category.

1. Gas Turbines

ABB Power
9 The Towers
Wilmslow Road
Didsbury
Manchester M20 2AB
Tel: 0161 448 4000

Alstom Gas Turbines Ltd (formerly Ruston Gas Turbines/European Gas)
PO Box 1
Lincoln LN2 5DJ
Tel: 01522 584 000

Centrax Ltd
Gas Turbine Division
Shaldon Road
Newton Abbot
Devon TQ12 4SQ
Tel: 01626 352251

Cooper Energy Services
Cooper Cameron House
5 Mondial Way
Harlington, Hayes
Middlesex UB3 5AR
Tel: 0181 990 1900

Genergy (formerly Dale Electric of GB Ltd)
Electricity Buildings
Filey
North Yorkshire Y014 9PJ
Tel: 01723 514141

Turbomeca Ltd
4/5 Grosvenor Place
London SW1X 7HH
Tel: 0171 235 3641

2. Reciprocating Engines

Allen Diesels (suppliers of Rolls Royce engines)
Crossley Works
Pottery Lane
Openshaw
Manchester M11 2DP
Tel: 0161 223 1353

Perkins Engines Ltd
Tixall Road
Stafford ST16 3UB
Tel: 01785 223141

Finning (UK) Ltd (suppliers of Caterpillar engines)
Power Systems Division
Watling Street
Cannock
Staffordshire WS11 3LL
Tel: 01543 461773

Mirrlees Blackstone
Hazel Grove
Stockport SK7 5AH
Tel: 0161 483 1000

Nedalo (UK) Ltd
Unit 3, Lawson Hunt Industrial Park
Broadbridge Heath
Horsham
West Sussex RH12 3JR
Tel: 01403 272 270

Ruston Diesel
Vulcan Works
Newton-Le-Willows
Merseyside WA12 8RU
Tel: 01925 225151

Stork Wartsila Diesel Ltd
Oak House
London Road
Sevenoaks
Kent TN13 1BL
Tel: 01732 460641

Waukesha Engine Division
Dresser UK Ltd
197 Knightsbridge
London SW7 1RJ
Tel: 0171 838 3011

3. Steam Turbines

Rolls Royce
Allen Steam Turbines
Queens Engineering Works
Ford End Road
Bedford MK40 4JB
Tel: 01234 272000

Alstom Energy
Newbold Road
Rugby
Warwickshire CV21 2NH
Tel: 01788 577111

Asea Brown Boveri
ABB Power Generation Ltd
Power House
Silverlink Business Park
Wallsend
Tyne and Wear NE28 9ND
Tel: 0191 295 2000

Siemens plc
Siemens House
Windmill Road
Sunbury-on-Thames
Middlesex
TW16 7HX
Tel: 01932 792800

KKK Limited
PO Box 23
Oxford House
Wellingborough
Northants
NN8 4JY
Tel: 01933 227220

Peter Brotherhood Ltd
Walton
Peterborough
PE4 6AB
Tel: 01733 292200

George Meller Ltd
Orion Park
Northfield Avenue
Ealing
London W13 9SJ
Tel: 0181 579 2111

4. Waste Heat Boilers

Wellman Robey Ltd
Newfield Road
Oldbury
West Midlands B69 3ET
Tel: 0121 552 3311

Beel Industrial Boilers plc
PO Box 148
Becor House
Green Lane
Lincoln LN6 7DN
Tel: 01522 510510

Clayton Thermal Products Ltd
3 Tatton Court
Kingsland Grange
Woolston
Warrington WA1 4RW
Tel: 01925 824279

Cochran Boilers Limited
Newbie Works
Annan
Dumfrieshire DG12 5QU
Tel: 01461 202111

Senior Thermal Engineering Limited
PO Box 80
Calder Vale Road
Wakefield WF1 5YS
Tel: 01924 780000

5. Gas Compressors

Atlas Copco (Great Britain) Ltd
PO Box 79
Swallowdale Lane
Hemel Hempstead HP2 7HA
Tel: 01442 261201

Belliss & Morcom
Icknield Square
Birmingham B16 0QL
Tel: 0121 454 3531

CompAir Broomwade Ltd
Hughenden Avenue
High Wycombe HP13 5SF
Tel: 01494 452901

Bryan Donkin Co Ltd
Derby Road
Chesterfield S40 2EB
Tel: 01246 273153

Hamworthy Compressors Ltd
Pump & Compressor Division
Chequers Bridge
Gloucester GL1 4LL
Tel: 01452 528431

6. Absorption Chillers

Apex Air Conditioning (suppliers of Robur ammonia chillers)
Rhodyate House
Woodhill
Avon BS19 5AF
Tel: 01934 838 190

Arun Environmental (suppliers of Robur ammonia chillers)
Fiscal House
2 Havant Road
Emsworth
Hampshire PO10 7JE
Tel: 01243 372 232

Birdsdall Services (suppliers of Robur ammonia, Kawasaki & Thermax LiBr chillers)
Unit 6
Frogmore Rd
Hemel Hempstead
Herts HP3 9RW
Tel: 01442 212 501

British Gas Services (suppliers of Robur ammonia chillers)
30 The Causeway
Staines
Middlesex TW18 3BY
Tel: 01784 890 708, Fax: 01784 874 930

Carrier Air Conditioning (suppliers of Carrier LiBr chillers)
Airport Trading Est
Biggin Hill
Kent TN16 3BW
Tel: 01959 571 211, Fax: 01959 571 009

Euro Controls (suppliers of Sanyo LiBr chillers)
Unit 16
Monument Industrial Estate
Chalgrove
Oxon OX44 7RW
Tel: 01865 400 526

McQuay International (suppliers of Sanyo LiBr chillers)
Bassington Lane
Cramlington
Northumberland NE23 8AF
Tel: 0191 201 0412, Fax: 01670 714 370

Thermax Europe Ltd (suppliers of Thermax LiBr chillers)
94 Alston Drive
Bradwell Abbey
Milton Keynes MK13 9HF
Tel: 01908 316 216, Fax: 01908 316 217

Trane UK Ltd (suppliers of Trane LiBr chillers)
Northern Cross
Basing View
Basigstoke RG21 4HH
Tel: 01256 306030, Fax: 01256 306031

York International Ltd (suppliers of York LiBr chillers)
Gardiners Lane South
Basildon
Essex SS14 3HE
Tel: 01268 28 7676, Fax: 01268 28 1765

The Government's Energy Efficiency Best Practice Programme provides impartial, authoritative information on energy efficiency techniques and technologies in industry, transport and buildings. This information is disseminated through publications, videos and software, together with seminars, workshops and other events. Publications within the Best Practice Programme are shown opposite.

Further information

For buildings-related publications please contact:
Enquiries Bureau
BRECSU
Building Research Establishment
Garston, Watford, WD2 7JR
Tel 01923 664258
Fax 01923 664787
E-mail brecsuenq@bre.co.uk

For industrial and transport publications please contact:
Energy Efficiency Enquiries Bureau
ETSU
Harwell, Didcot, Oxfordshire,
OX11 0RA
Fax 01235 433066
Helpline Tel 0800 585794
Helpline E-mail etbppenvhelp@aeat.co.uk

Energy Consumption Guides: compare energy use in specific processes, operations, plant and building types.

Good Practice: promotes proven energy efficient techniques through Guides and Case Studies.

New Practice: monitors first commercial applications of new energy efficiency measures.

Future Practice: reports on joint R & D ventures into new energy efficiency measures.

General Information: describes concepts and approaches yet to be fully established as good practice.

Fuel Efficiency Booklets: give detailed information on specific technologies and techniques.

Energy Efficiency in Buildings: helps new energy managers understand the use and costs of heating, lighting etc.